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Analysis of SO2 Emission Control Alternatives for the Cabras Power Plant, Guam Power Authority

PEDCo-Environmental Specialists, Inc, Cincinnati, Ohio

Prepared for

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ANALYSIS OF SO_2 EMISSION CONTROL ALTERNATIVES FOR THE CABRAS POWER PLANT, GUAM POWER AUTHORITY

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ANALYSIS OF SO_2 EMISSION CONTROL ALTERNATIVES FOR THE CABRAS POWER PLANT, GUAM POWER AUTHORITY

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Guam Power Authority and the U.S. Navy own and operate the nine power generating facilities on Guam. None of the powerplants on Guam have any control equipment for particulate or sulfur emission. All plants exceed Guam's emission rate regulation for existing sources and three plants have been responsible for SO2 episode levels. This report explores several options for meeting the SO2 emission limitation.

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Under a separate contract, Foster Associates analyzed the availability of low sulfur fuels and system reliability and economics. Information from the Foster studies is included in appropriate sections of this report. The Foster Associates Project Managers were Messrs. Jack D. Colclough and Robert H. Sarikas.

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SUMMARY

The Guam Power Authority (GPA) and the United States Navy own and operate the power generating facilities on the Island of Guam that supply electrical power to the Island Wide Power System. The facilities consist of four steam plants and five diesel plants.

The Cabras Steam Plant is owned by GPA and consists of one 66 megawatt fuel oil fired unit. Plans call for the addition of three more identical boilers (66 MW each) in 1975, 1977 and 1978.

The Piti Steam Plant is owned and operated by the U.S. Navy and consists of five oil fired units. Boilers 1, 2, and 3 supply steam to Units 2 and 3 which have capacities of 11.5 megawatts each. Units 4 and 5 are rated at 22.5 megawatts each.

The Tanguisson plant is operated by the GPA. GPA owns Unit 2 and the Navy owns Unit 1. The plant consists of two identical fuel oil fired boilers rated at 26.5 megawatts each.

The Inductance Power Barge is leased and operated by the GPA. It consists of two fuel oil fired boilers coupled to a single 28 MW unit.

None of the power plants on Guam have any control equipment for particulate or sulfur dioxide emissions. At present all burn No. 6 fuel oil having 3.1 percent sulfur at 18,740 BTU/lb. Emission rates are estimated at 0.05 lb of particulate/MM BTU, and 3.3 lbs SO_2/MM BTU. Guam has only one quantitative emission rate regulation for existing sources, that being 0.80 lb SO_2/MM BTU. All the power plants exceed this standard. In addition, the Cabras plant is subject to Federal New Source Performance Standards (NSPS). The NSPS limitations are 0.10 lb particulate/MM BTU, 0.8 lb SO_2/MM BTU and 0.3 lb NO_x/MM BTU.

GPA proposed to comply with applicable emisison standards by burning low sulfur fuel oil in all units. Two requests for bids to supply low sulfur fuel oil were unsuccessful. No alternative compliance plans have been formulated by GPA.

The Guam power plants also have a severe effect on air quality. The Tanguisson plant, the Power Barge Inductance and particularly the Piti plant have all been responsible for episode levels of SO_2. No episode cases have been attributed to the Cabras plant. Modeling studies for both the Cabras and Piti plants indicate that to avoid violation of ambient air standards, 0.75 percent sulfur oil must be burned and the Piti plant must add 200 foot high stacks. These modeling studies are of questionable validity, however, because of unusual site and terrain characteristics.

Several options are available for meeting the SO_2 emission limitations. Alternatives evaluated include use of low sulfur fuel oil, flue gas desulfurization, use of low sulfur coal, and burning of refuse in the units.

Oil with a sulfur content no greater than 0.85% S (assuming 18,740 BTU/lb) would be required to meet the emission standard. Such oil is available from Arabia and Indonesia, at costs ranging from $11.95 to $13.20 per barrel ($1.93 to $2.13/MM BTU). This represents an increase in fuel costs of 2 to 22 cents/MM BTU or 0.32 to 3.52 mills/KWH.

Flue gas desulfurization systems were evaluated for the Cabras and Tanguisson plants. Both limestone and seawater scrubbing systems are suitable for installation at these plants. Capital and operating costs for the flue gas desulfurization options as well as the use of low sulfur oil are presented in Table 1. Also included is the anticipated increase in the average residential consumers monthly bill.

Low sulfur coal is not a viable alternative for the Cabras plant due to the severe derating that the units would incur if converted. Coal is available from Australia that could meet the SO_2 emission regulations; it should be considered as a possible fuel for Cabras Units 3 and 4.

Solid waste could be used to supplement existing fuel supplies but will not ease the fuel requirements for the Guam power plants. A detailed study would be required, however, to assess the practicability of such a combined firing system on Guam.

Table 1. COST COMPARISON OF THE VARIOUS ALTERNATIVES FOR MEETING SO_2 EMISSION REGULATIONS

Option	Capital		Annual[a]		Increase in avg. monthly bill $	Change in avg. monthly bill %
	$ MM	$/KW	$ MM	mills/KWH		
Present fuel	0	0	0	0	0	0
Arabian low sulfur oil	0	0	0.22	0.32	0.32	0.6
Indonesian low sulfur	0	0	2.23	3.20	3.20	5.6
Limestone scrubbing (Cabras 1 and 2)	9.22	69.81	3.65	4.21	4.21	7.4
Limestone scrubbing (Tanguisson 1 and 2)	6.24	117.81	1.96	7.02	7.02	12.3
Limestone scrubbing (Cabras and Tanguisson)	13.28	71.78	5.18	5.52	4.52	7.9
Seawater scrubbing (Cabras 1 and 2)	5.38	40.74	1.85	2.13	2.13	3.7
Seawater scrubbing (Tanguisson 1 and 2)	3.18	59.91	1.06	3.82	3.82	6.7

[a] Annualized costs do not include oil cost savings resulting from the use of lower cost, higher sulfur content fuel oil in conjunction with the FGD systems

A noncontinuous emission limitation could be initiated on Guam to avoid violations of the ambient air standards. Such a system would require the installation of weather forecasting equipment, air quality monitors, additional personnel, an alternate low sulfur fuel oil (0.75% S) supply system for each plant, and 200 foot high stacks at the Piti plant. An effective supplementary control system would minimize violations of the ambient air standards but would not meet emission limitation regulations.

If only the Cabras unit is brought into compliance, four alternatives are available:

1. Shut down the plant.
2. Burn low sulfur oil.
3. Install limestone scrubbers.
4. Install seawater scrubbers.

Table 2 lists the advantages and disadvantages of each alternative plus identifies their expected impact on electricity costs. The evaluation indicates that bringing the Cabras units into compliance with NSPS will have little effect on the average residential electricity bill.

Table 2. COMPARISON OF ALTERNATIVES FOR CONTROLLING SO_2 EMISSIONS FROM THE CABRAS POWER PLANT

Option	Capital $ MM	Annualized	Change in average monthly electric bill		Earliest implementation date	Advantages/disadvantages
			$	%		
Shut down Cabras plant	0	5.34	7.66	13.4	0 months	1. Compliance is achieved in the shortest possible time. 2. Reliability of the electric system with this plan is unacceptable after 1976. 3. A large capital investment is abandoned. 4. Electric rates are increased.
Low sulfur oil	0	0.22	0.32	0.6	0-6 months	1. Compliance is achieved in the shortest possible time without shutting down the Cabras plant 2. System reliability is satisfactory. 3. A contract with GORCO must be broken.
Limestone scrubbers[a]	9.22	0.93	1.33	2.3	30 months	1. Compliance is achieved. 2. Low-cost fuel (Arabian high-sulfur) may be used. 3. System reliability is satisfactory. 4. Land may be reclaimed with scrubber sludge. 5. Compliance is not achieved for 20 months. 6. Unstabilized scrubber sludge could affect island ground-water supplies; stabilized sludge probably would not create ground-water contamination problems. 7. Secondary environmental impacts of increased truck traffic to carry sludge and limestone would need to be explored. 8. Scrubber sludge could cause fugitive dust problems without careful design.
Seawater scrubbers[a]	5.30	(0.52)	(0.75)	(1.3)	24 months	1. Compliance is achieved. 2. Low cost fuel (Arabian high-sulfur) may be used. 3. System reliability is satisfactory. 4. Compliance is not achieved for 24 months. 5. An environmental impact statement must be prepared describing the ecological effects of the system. Since the effects are unknown at present, an extensive study is required. 6. To date this system has been used to a limited extent.

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[a] Cost includes credit for burning high sulfur Arabian fuel oil.

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1.0 INTRODUCTION

Pursuant to Section 111 of the Clean Air Act, the Administrator of the U.S. Environmental Protection Agency (EPA) promulgated standards of performance for new and modified fossil-fuel-fired steam generators; the standards pertain to plume opacities and emissions of particulate, sulfur dioxide, and oxides of nitrogen. These New Source Performance Standards (NSPS) are applicable to each fossil-fuel-fired steam generating unit constructed or modified after August 1971 and having capacity of more than 63 million Kcal (250 MM BTU) per hour heat input.

The Guam Power Authority (GPA) recently started operation of Cabras Power Plant, Unit 1. It was proposed initially that this unit burn low-sulfur fuel oil. Because of tightened fuel oil supplies and increasing fuel prices, however, GPA did not procure low-sulfur fuel oil.

The U.S. Environmental Protection Agency retained PEDCo-Environmental Specialists to evaluate the options available to GPA for meeting the NSPS. A PEDCo team conducted a field survey on Guam from December 9-12, 1974, and met with representatives of the Guam Environmental Protection Agency, the Guam Power Authority, the U.S. Navy, and the Guam Oil Refining Company (GORCO).

Four plants of the Island-Wide Power System (IWPS) were inspected: Cabras, Piti, Tanguisson, and Inductance. Control options were evaluated for the Piti and Tanguisson plants, as well as the Cabras Plant, so that the analysis could consider possible economies of scale (e.g. in installation and operation of flue gas desulfurization equipment) and possible application of system-wide controls (e.g. fuel switching, load shifting).

Background information on Guam and the Guam Power Authority is given briefly below.

Guam

Guam is located in the western Pacific, approximately 3700 miles from Hawaii and 6000 miles from San Francisco. The island is about 30 miles long, and its width ranges from 4 to 6-1/2 miles. The land mass encompasses approximately 210 square miles. Guam's population numbers approximately 110,000. Guamanians account for 56 percent of the total population, military personnel 28 percent, state-siders 7 percent, and Phillipinos 6 percent; the remainder consists of Chinese, Japanese, Koreans, and other ethnic groups.

Following the Spanish-American War in 1898, Guam became a U.S. possession under the administration of the U.S. Navy. In 1950 Congress enacted the Organic Act, placing the island under a civilian administrator, a Governor appointed by the President. The first popular election for Governor of Guam was in November 1970.

Tourism is probably the single most important factor in the economy. Over the past several years this industry has grown at a tremendous rate, from barely 2000 visitors in 1964 to more than 215,000 in 1973. Approximately 75 percent of all visitors to Guam are classed as tourists. Most come from Japan, approximately 72 percent; the United States ranks second with 16 percent, followed by the trust territory and others, with 5 and 7 percent respectively. Various economic indicators for selected years are presented in Table 1.1.

The Guam Power Authority (GPA)

GPA provides electrical service to the civilian population of Guam. In 1975 GPA will provide service to all customers in Guam, including the military.

Historically the electric power system on Guam has been owned and operated by the U.S. Navy. When Guam was granted territorial status in 1950, responsibilities for power distribution were transferred from the Navy to the Public Utility Agencies of Guam (PUAG). At that time the agency had responsibility for all utility services to civilian customers. In 1968 the Guam Power Authority was formed by an act of the Guam Legislature. In October 1972, GPA and the Navy signed an agreement establishing 1975 as a target date when GPA will assume full control of operation of the Island-Wide Power System.

Civilian and military power requirements have increased approximately 82 percent, from 83.5 megawatts in 1967 to 152.1 megawatts in 1973. This increase represents an average growth rate of 10.5 percent per year. In 4 years electrical power requirements doubled from 181 million kilowatt-hours in 1969 to 361 million kilowatt-hours in 1973. The number of civilian customers served in 1973 was 19,942, an increase from 12,885 in 1969.

2.0 ISLAND-WIDE POWER SYSTEM

The Guam Power Authority is a government-owned system providing electricity to all of Guam's service areas. The United States Navy owns and operates some of the production and transmission facilities, which are used jointly for the supply of electric power to Department of Defense installations and to GPA for resale to their customers.

In October 1973 GPA and the Navy entered into a power pool agreement, which provides for the operation by each of their respective production and transmission facilities to meet power requirements of the Island-Wide Power System (IWPS). The agreement calls for full control of IWPS operation by the Guam Power Authority by late 1975.

The IWPS generating units and power generation requirements are discussed in the following sections.

2.1 PHYSICAL PLANT FACILITIES

2.1.1 Cabras Steam Plant

The Cabras Steam plant is located on Cabras Island near the western shore of Guam and adjacent to the site of the Piti Steam plant. Only Unit 1 (66 MW) is presently operating, having become operational in September 1974. When the plant is completely operational, four identical boilers, rated at 66 MW each, will provide a total plant capacity of 264 MW.

Unit 2 will be operational in May 1975, Unit 3 in 1977, and Unit 4 in 1978. The Cabras plant will then be the largest generating station on Guam and will provide most of the island's power-generating capacity. Cabras is owned and operated by the Guam Power Authority and is part of the Island-Wide Power System. The boilers for Units 1 and 2, manufactured by Babcock and Wilcox Company, are designed to burn oil. Each boiler will exhaust through a separate stack. Height of the stack for Unit 1 is 200 feet; Unit 2 will have a 400-foot stack. Stack heights for Units 3 and 4 are not known.

A completed survey form giving detailed operations and emissions data of the Cabras plant is presented in Appendix A.

2.1.2 Piti Steam Plant

The Piti Steam plant is located on the western shore of Guam near Cabras Island. The plant is owned and operated by the Navy and is part of the Island-Wide Power System. The Piti plant now provides the largest installed capacity on the island, with five units giving a total generating capacity of 79.5 megawatts.

The five boiler/turbine generating units at the Piti plant were manufactured by Combustion Engineering and were designed to burn oil only. Units 1 and 2 were placed in operation in 1951, Unit 3 in 1953, Unit 4 in 1964, and Unit 5 in 1965. Capacities of units 1, 2, and 3 are rated at

11.5 MW each; Units 4 and 5 are rated at 22.5 MW each. Although turbine 1 has been decommissioned, Boiler 1 remains in operation supplying steam to Turbines 2 and 3. Each boiler exhausts through a separate stack. Stacks for Boilers 1, 2, and 3 are 88 feet 8 inches high; stacks for Boilers 4 and 5 are 75 feet 7 inches high.

A completed plant survey form of the Piti plant is presented in Appendix B.

2.1.3 Tanguisson Steam Plant

The Tanguisson plant is located on the western shore of Guam, near Tumon Bay below Two Lover's Leap. Guam Power Authority is the owner of Unit 2 and operator of the entire plant. The Navy owns Unit 1. The plant consists of two base-loaded, Combustion Engineering boilers, rated at 26.5 MW each and designed to burn oil. Total plant capacity is 53 MW. Unit 1 was installed in 1971 and Unit 2 in 1972. Each unit exhausts through a separate 131-foot stack.

A completed plant survey form of the Tanguisson plant is presented in Appendix C.

2.1.4 Inductance Power Barge

The Inductance Power Barge is located off the western shore of Guam at Polaris Point in outer Apra Harbor. The barge is operated by the Guam Power Authority and is part of the Island-Wide Power System. The Army owns the barge and leases it to the Navy, which in turn leases it to GPA. The Power Barge consists of two Babcock and Wilcox boilers, which are used for peaking purposes. Both boilers are rated at 14 MW and are designed to burn oil. The two boilers are coupled to a single turbine rated at 28 MW. The barge was built in 1943 and towed to the island in 1971. Each boiler exhausts through a separate 64-foot stack.

A completed survey form of the Inductance Power Barge is presented in Appendix D.

2.1.5 Other Power Generation

In addition to the four power plants just described, which burn No. 6 fuel, the Navy and GPA operate diesels at Dededo, Tamuning, Agana, Barrigada, and Orote. Details of the ownership, size, and the number of units at the diesel plants and the four power plants are presented in Table 2.1.

None of the power plants on Guam is equipped with systems for continuous control of sulfur dioxide or particulate emissions. The Piti units have opacity meters for detection of visible particulate emissions.

2.2 POWER GENERATION REQUIREMENTS AND RELIABILITY[a]

2.2.1 Power Generating Requirements

The combined load of the Island-Wide Power System is expected to reach a peak demand of 162.8 MW in 1975. The coincident demand excluding transmission losses is projected to reach 156.8 MW in 1975. System peak demand is expected to increase at a compound annual rate of 11.2 percent.

The energy requirement of the system is projected to be 992.4 GWHR in 1975. The forecasted compound rate of in-

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[a] Information for this section was prepared by Foster Associates, Washington, D.C.

Table 2.1 SUMMARY OF ISLAND WIDE POWER SYSTEM CHARACTERISTICS

Plant	MW	Owner	Operator	Service	Comments
Piti					
1	11.5	Navy	Navy	Floating	Unit 1 turbine decommissioned; boiler still in use.
2	11.5	Navy	Navy	Floating	
3	11.5	Navy	Navy	Floating	
4	22.5	Navy	Navy	Floating	
5	22.5	Navy	Navy	Floating	
Cabras					
1	66.0	GPA	GPA	Floating	Startup May 1975
2	66.0	GPA	GPA	Floating	Planned January 1978
3	66.0	GPA	GPA	Floating	Planned July 1978
4	66.0	GPA	GPA	Floating	
Tanguissan					
1	26.5	Navy	GPA	Floating	
2	26.5	GPA	GPA	Floating	
Inductance	28	Army	GPA	Floating	Two boilers for one turbine
Dededo					
1	2.5	GPA	GPA	Peaking	
2	2.5	GPA	GPA	Peaking	
3	2.5	GPA	GPA	Peaking	
4	2.5	GPA	GPA	Peaking	
Tamuning					
1	2.5	GPA	GPA	Peaking	
2	2.5	GPA	GPA	Peaking	
3	2.5	GPA	GPA	Peaking	
4	2.5	GPA	GPA	Peaking	
Agana					
1	0.6	Navy	Navy	Peaking	One of the Agana units has been permanently disconnected.
2	0.6	Navy	Navy	Peaking	
3	0.6	Navy	Navy	Peaking	

Table 2.1 (continued) SUMMARY OF ISLAND WIDE POWER SYSTEM CHARACTERISTICS

Plant	MW	Owner	Operator	Service	Comments
Agana					
4	0.6	Navy	Navy	Peaking	
5	0.6	Navy	Navy	Peaking	
6	0.6	Navy	Navy	Peaking	
7	0.6	Navy	Navy	Peaking	
8	0.6	Navy	Navy	Peaking	
9	0.6	Navy	Navy	Peaking	
10	0.5	Navy	Navy	Peaking	
Barrigade					
1	2.0	Navy	Navy	Peaking	Units 1 and 2 are dedicated standbys to Naval Communication Center
2	2.0	Navy	Navy	Peaking	
3	2.0	Navy	Navy	Peaking	
4	2.0	Navy	Navy	Peaking	
5	2.0	Navy	Navy	Peaking	
6	2.0	Navy	Navy	Peaking	
Orote					
1	0.6	Navy	Navy	Peaking	
2	0.6	Navy	Navy	Peaking	
3	0.6	Navy	Navy	Peaking	
4	0.6	Navy	Navy	Peaking	
5	0.6	Navy	Navy	Peaking	
6	0.6	Navy	Navy	Peaking	
7	0.6	Navy	Navy	Peaking	
8	0.6	Navy	Navy	Peaking	
9	0.6	Navy	Navy	Peaking	
10	0.6	Navy	Navy	Peaking	

Notes: 1. The floating units are loaded in the following order: Cabras, Tanguisson, Piti 4 and 5, Piti 1, 2, and 3, Inductance.
2. The GPA diesels are loaded before the Navy diesels.

crease in energy requirements is 10.8 percent per year. The system annual load factor is projected to be about 70 percent.

Table 2.2 provides a breakdown of the IWP System peak load by year. Table 2.3 is a summary of the peak demand and energy data used in the study.

2.2.2 Power Generation Reliability

In evaluating system reliability five alternatives for supplying present and expected future load requirements were studied. An analysis of the system reliability was made for each of the five plans. These plans are described in the following paragraphs:

Plan A

This plan proposes that the Cabras Plant not be operated until sometime after 1980. Units 1 and 2 would be "mothballed" and Units 3 and 4 would not be built during the period of the study.

All other existing diesel and steam-turbine capacity would be maintained to meet load requirements. The total capacity of this system would be 222 MW.

Plan B

This plan is the currently proposed expansion plan for the system. It calls for the operation of Cabras No. 1 in 1974, Cabras No. 2 in 1975, Cabras No. 3 in 1978, and Cabras No. 4 in 1979. Each of these units is to have a rating of 66 MW.

Table 2.2 SUMMARY OF ISLAND-WIDE POWER SYSTEM DEMAND

YEAR	UNITED STATES NAVY			GUAM POWER AUTHORITY			TOTAL		
	PEAK DEMAND (MW)	INCREASE (MW)	INCREASE (%)	PEAK DEMAND (MW)	INCREASE (MW)	INCREASE (%)	PEAK DEMAND (MW)	INCREASE (MW)	INCREASE (%)
1970	59.4	-	-	41.8	-	-	101.2	-	-
1971	66.3	6.9	11.6	49.2	7.4	17.7	115.5	14.3	14.1
1972	72.6	6.3	9.5	56.2	7.0	14.2	128.8	13.3	11.5
1973	68.1	(4.5)	(6.2)	70.9	26.7	47.7	138.5	22.2	17.2
1974	65.0	(3.1)	(4.6)	79.8	8.9	12.8	144.8	5.8	4.2
1975	70.0	5.0	7.7	86.8	7.0	8.8	156.8	12.0	8.3
1976	75.0	5.0	7.1	94.7	7.9	9.1	169.7	12.9	8.2
1977	80.0	5.0	6.7	107.7	13.0	13.8	187.7	18.0	10.6
1978	85.0	5.0	6.2	131.3	23.6	22.0	216.3	28.6	15.2
1979	90.0	5.0	5.9	145.9	14.6	11.1	235.9	19.6	8.3

Table 2.3 SUMMARY OF LOAD DATA

ISLAND-WIDE POWER SYSTEM

YEAR	PEAK DEMAND (MW)	MINIMUM DEMAND (MW)	ENERGY (GWHR)	LOAD FACTOR (%)
1975	162.8	72.3	992.4	69.6%
1976	180.5	80.1	1072.9	67.9
1977	199.7	88.6	1187.5	67.9
1978	230.1	102.1	1369.0	67.9
1979	251.9	111.8	1497.5	67.9
1980	280.9	124.7	1659.7	67.4

In addition, retirements of 44 MW, 28 MW, and 10 MW are scheduled for 1975, 1978 and 1979 respectively. These retirements are to be concurrent with the Cabras units. The retired capacity will consist of diesel units of 600 KW, 2.0 MW, and 2.5 MW, and steam-turbine capacity of 11.5, 20 and 28 MW. Two of the units to be retired are power barges.

Plan C

This plan calls for the Cabras Unit No. 1 to be placed on "cold stand-by" until 1977. Cabras Unit No. 2, which is nearing completion, is to be placed on "cold stand-by" status until 1978.

The existing capacity is to be retained in service and used to serve existing and future loads.

The timing, as will be discussed in more detail later, is based on the maintaining of a system which is no less reliable than the one presented in Plan B.

This plan is predicated on the assumption that the Cabras units could not be brought into compliance with emission standards. It also presupposes that any plan with less reliability than Plan B would be unacceptable.

Plan D

This plan is the same as Plan B except that the operating costs are calculated on the basis of using low-sulfur fuel.

Plan E

This plan is based on the assumption that the Cabras Plant can be brought into compliance with emission standards in 1976 by purchasing low-sulfur oil. It proposes that both Units 1 and 2 at Cabras be placed in service starting in 1976, using low-sulfur oil as a fuel. All other existing capacity would be retained in service and used to serve system load.

The third and fourth units at Cabras would not be constructed until after 1980. An earlier construction of these units, provided they are also in compliance, could be scheduled if fuel prices and the differential heat rates justify the capital expenditure.

The results of the analysis of the reliability of the alternative plans considered indicate that the operation of the Cabras Plant can be delayed until 1977. At that time Cabras Unit No. 1 or other suitable capacity must be placed in service to maintain adequate reliability. Capacity must again be added in 1978 to maintain adequate reliability. Operation of four units at Cabras does not result in significant improvement in system reliability.

The currently planned retirements of diesel and steam turbine capacity must be delayed until after 1980 to maintain system reliability and serve load if the Cabras units are not placed in service.

The economic analysis indicates that a significant reduction in system fuel cost is possible if the Cabras Units 1 and 2 can be made to meet emission standards rather than delay operation of these units until needed to maintain system reliability.

The reliability study is based upon a probability analysis of the generating system for each plan. It was made using a computer program to calculate the cumulative probability of the availability of varying amounts of capacity. The calculations were made for each year of each plan. The measure of the reliability of each plan was the probability that capacity would always be greater than or equal to the system load (positive margin).

The probability of positive margin was mathematically converted into the probable number of days each year on which there would be insufficient capacity to supply the load. These figures can then be totaled over the study period to form a basis of comparison.

Results of the reliability analysis are summarized in Table 2.4.

Table 2.4 SYSTEM RELIABILITY

Plan	Total probable days of unserved load over a 10-year period
A	Unacceptable
B	6.36
C	8.17
D	6.36
E	4.91

As can be seen from the above table, the reliability of the system with only two Cabras units added in 1976 (Plan E) is greater than the plan with four Cabras units (Plans B and D). The greater reliability results from the fact that there are no retirements called for in Plan E.

Plan C which calls for the operation of the first two Cabras units in 1977 and 1978 is no less reliable than the four unit plans except in 1980. Plans B and D are the same in terms of reliability. They differ only in the type of fuel used.

As a point of reference, a commonly used "yardstick" of reliability is that a system has acceptable reliability provided that there is not more than one day of unserved load in ten years.

It is possible to observe the influence of unit size on reliability. Table 2.5 shows the percent reserve and probable days of unserved load for different conditions.

Table 2.5 EFFECT OF CABRAS UNITS ON SYSTEM RESERVE REQUIREMENTS AND PROBABILITY OF UNSERVED LOAD

Condition	Reserve Percentage	Probable Number of Days of Unserved Load
No Cabras units	36.4%	0.15
Two Cabras units	36.2	0.51
Three Cabras units	40.5	2.47

From Table 2.5 it can be seen, that maintaining approximately the same reserve percentage, an increase in the number of large units will result in decreased reliability. If reliability is to be maintained as the unit size is increased, then percent reserve must be increased.

3.0 ATMOSPHERIC EMISSION RATES AND REGULATIONS

Chapter 13, Section A, of the Guam Air Pollution Control Standards and Regulations limits sulfur dioxide emissions to 0.80 pound of sulfur dioxide per million BTU heat input from any stationary combustion source. In addition, the Cabras Unit No. 1 is subject to Federal New Source Performance Standards (40 CFR 60), which are summarized in Table 3.1. In addition to maximum emission rates, NSPS also specify requirements for performance testing, stack and process monitoring, and recordkeeping and reporting.

Guam Air Pollution Regulations do not limit mass emissions of particulate from gas or oil-fired stationary combustion sources. These sources are governed by visible emission regulations (Chapter 10 of the Regulations). Continuous discharges are limited to 20 percent opacity or No. 1 Ringelmann. During a period of 60 minutes, discharges may exceed 60 percent opacity or No. 3 Ringelmann for 3 minutes.

Emissions of carbon monoxide and nitrogen oxides are limited only indirectly by ambient air quality standards. There are no regulations limiting emission of these contaminants from stationary sources.

Table 3.1 SUMMARY OF NSPS EMISSION STANDARDS FOR NEW AND MODIFIED STEAM GENERATORS

Item	Standard	Fuel
Opacity	20%	All
Particulate	0.18 gm/MM cal input (0.10 lb/MM BTU input)	All
SO_2	1.4 gm/MM cal input (0.8 lb/MM BTU input)	Oil
SO_2	2.2 gm/MM cal input (1.2 lb/MM BTU input)	Coal
SO_2		Combination
NO_x	0.36 gr/MM cal input[a] (0.20 lb/MM BTU input)	Gas
NO_x	0.54 gr/MM cal input[a] (0.30 lb/MM BTU input	Oil
NO_x	1.26 gr/MM cal input[a] (0.70 lb/MM BTU input)	Coal[b]
NO_x	Prorated	Combination

[a] Expressed as NO_2.

[b] Except lignite.

Emissions of sulfur dioxide from GPA power plants are estimated to be 3.3 lb/MM BTU, more than four times the rate allowable under both Guam EPA and Federal EPA standards.

4.0 AIR QUALITY IMPACT

4.1 AIR QUALITY DATA

The present air quality monitoring system on Guam consists of six fixed stations and several mobile stations. The fixed sampling sites are shown in Figures 4.1 and 4.2, with locations of the Cabras, Inductance, Piti, and Tanguisson Power plants.

Ambient Air Quality Standards for the Territory of Guam are presented in Table 4.1. Table 4.2 lists the days on which the SO_2 air quality standards were exceeded and the apparent source of emission. Comparison of the air quality data and the SO_2 air quality standard reveals the severe impact of Guam's power plants on the island's air quality.

The Piti Power Plant is responsible for most of the violations of air quality standards. Episode levels occurred at the USO facilities when westernly winds from 7 to 16 miles per hour carried flue gases from the Piti plant toward these facilities. Westerly winds occur infrequently (only about 5 percent of the time); prevailing winds are from the east.

An ambient air sampling program was conducted by a Naval Civil Engineering Laboratory in May 1973 to measure

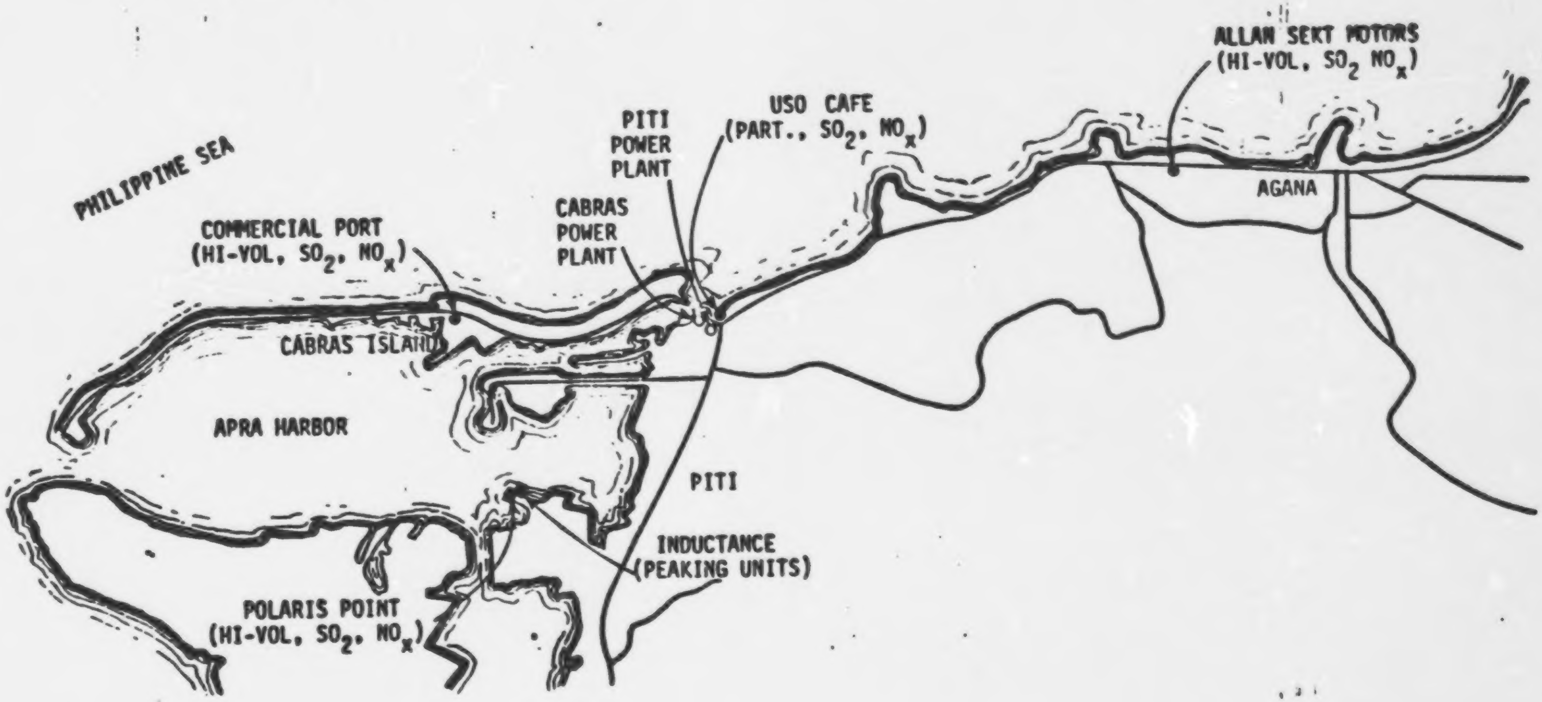

PHILIPPINE SEA
COMMERCIAL PORT (HI-VOL, SO_2, NO_x)
CABRAS ISLAND
APRA HARBOR
POLARIS POINT (HI-VOL, SO_2, NO_x)
CABRAS POWER PLANT
PITI POWER PLANT
USO CAFE (PART., SO_2, NO_x)
PITI
INDUCTANCE (PEAKING UNITS)
ALLAN SEKT MOTORS (HI-VOL, SO_2 NO_x)
AGANA

Figure 4.1 Location of ambient air quality monitors.

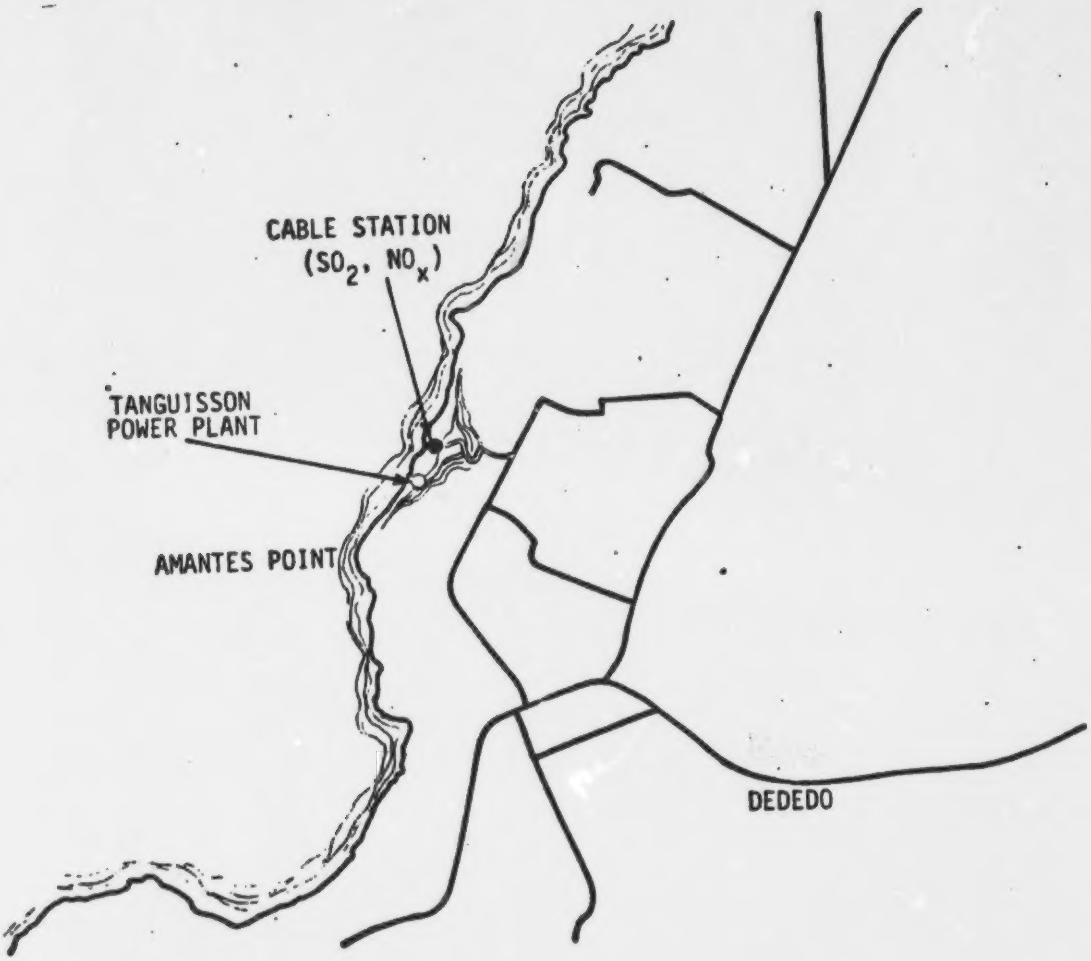


Figure 4.2 Location of ambient air quality monitors near the Tanguisson Power Plant.

Table 4.1 AMBIENT AIR QUALITY STANDARDS FOR THE TERRITORY OF GUAM

Pollutant	Level not to exceed	Time period
Sulfur oxides	60 $\mu g/m^3$ (0.02 ppm)	Annual arithmetic mean.
	365 $\mu g/m^3$ (0.12 ppm)	Maximum 24-hour concentration not to be exceeded more than once per year.
	1300 $\mu g/m^3$ (0.5 ppm)	Maximum 1-hour concentration not to be exceeded more than once per year.
	650 $\mu g/m^3$ (0.25 ppm)	Maximum 4-hour concentration not to be exceeded more than once per year.
Particulate matter	60 $\mu g/m^3$	Annual geometric mean.
	150 $\mu g/m^3$	Maximum 24-hour concentration not to be exceeded more than once per year.
	360 $\mu g/m^3$	Maximum 8-hour concentration not to be exceeded more than once per year.
Carbon monoxide	10 $milligrams/m^3$ (9 ppm)	Maximum 8-hour concentration not to be exceeded more than once per year.
	40 $milligrams/m^3$ (35 ppm)	Maximum 1-hour concentration not to be exceeded more than once per year.
Photochemical oxidants	160 $\mu g/m^3$ (0.08 ppm)	Maximum 1-hour concentration not to be exceeded more than once per year.
Hydrocarbons	160 $\mu g/m^3$ (0.24 ppm)	Maximum 3-hour concentration not to be exceeded more than once per year.
Nitrogen oxides	100 $\mu g/m^3$ (0.05 ppm)	Annual arithmetic mean.

Table 4.2 EPISODE CHRONOLOGY FOR THE TERRITORY OF GUAM (1972-1974)

Date	SO_2 µg/m^3	Location	Source	Sampling period, hours
7/20/72	1095	USO cafe	Piti	48
7/26/72	3497	USO cafe	Piti	24
7/27/72	3215	USO cafe	Piti	24
10/3/72	733	USO cafe	Piti	24
10/3/72	397	USO shed	Piti	24
10/10/72	1368	USO shed	Piti	24
10/11/72	695	USO shed	Piti	24
10/12/72	498	USO shed	Piti	24
10/28/72	681	USO shed	Piti	24
10/28/72	830	USO bathhouse	Piti	24
11/14/72	2775	Station 3	YFP-10	1
11/21/72	400	Proteus Point	YFP-10	24
8/13/74	1536	Santos Park	Piti	1
3/3/74	873	SRF	Inductance	24
8/14/74	1005	USO pavillion	Piti	1
8/14/74	1197	Santos Park	Piti	1
8/15/74	1058	USO pavillion	Piti	1
8/15/74	1053	USO bathhouse	Piti	1
11/18/74	844	Cable station	Tanguissan	24

the impact of the Piti Plant under the prevailing easterly winds. The samplers were located west of the Piti Plant at varying distances. Results of this sampling, presented in Table 4.3, are similar to the readings taken at the USG facilities.

Episode occurrences also have resulted from emissions from the Inductance, the Tanguisson Power Plant, and the now-retired YFP 10 power barge. No episode conditions caused by the Cabras Plant have been reported.

4.2 RESULTS OF AIR QUALITY MODELING

Two studies have been conducted using mathematical models to predict SO_2 ground level concentrations resulting from emissions from the Cabras and Piti Power plants. Both studies, by EPA and by Naval Civil Engineering Laboratory, used the PTMTP model from EPA's UNAMAP system. This model does not account for such dispersion interferences as buildings, coastal location, or uneven topographical features. Because of this limitation the model does not simulate accurately the conditions at the Piti Plant, where the height of the stacks relative to height of the boiler house causes flue gas downwash. Both studies assumed stack heights of 200 feet for the Piti Plant, whereas height of the four Piti stacks ranges from 75 to 89 feet. It is emphasized that the results of these modeling studies are of limited utility, indicating only the relative impact on air quality of changing such parametric values as stack height and emission rates.

The EPA study was centered on short time intervals up

Table 4.3 NCEL MEASUREMENTS OF AMBIENT SO_2 NEAR THE PITI PLANT

1973 Date	Duration of sampling hours	SO_2 measurements, $\mu g/m^3$			
		Site 1	Site 2	Site 3	Site 4
May 30	2	9.4			
	2	9.8			
	2	11.8			
	1		3278		
May 31	3	41.3			
	2		1536		
	7	50.9			
	1			1019	
June 1					
	1				3957
	1				4897
	1			4081	
	1				3265
	1			4244	
	1	3.3			

Note 1: Winds were from the prevailing easterly direction throughout the measuring period.

Note 2: Site 1 was located about 150 feet upwind of the plant. Sites 2, 3, and 4 were 800, 200, and 225 feet downwind of the plant.

Note 3: Two additional measurements made inside the plant fence about 50 feet downwind of the stacks yielded values of 1438 and 3904 μg/m over time intervals of 35 and 10 minutes, respectively.

to 4 hours and applied the most severe meteorological conditions. Stability Condition 1 represents an unstable condition caused by rapid heating of the ground under clear skies, high sun elevation, and low wind speeds resulting in turbulent mixing, which brings stack emissions down to ground level in relatively high concentrations within a relatively short distance from the stack.

The cases evaluated for the Cabras and Piti plants include normal and maximum operating load conditions for the time period spanning 1976 through 1978, including provision for one Cabras unit out of service for overhaul. Operating loads for each unit were keyed to load projections by the Guam Power Authority and the assumed use of 0.75 percent sulfur fuel by both plants.

Table 4.4 presents results of the EPA modeling. Data for runs 8 and 11 indicate a future problem if the proposed 4-hour standard of 650 $\mu g/m^3$ is adopted. It appears that satisfactory air quality can be obtained through 1978 if the Piti Plant is equipped with 200-foot stacks and the Cabras and Piti plants burn 0.75 percent sulfur oil. Once loads reach or exceed the projected 1978 levels, use of oil containing 0.5 to 0.6 percent sulfur may be required to avoid violation of the proposed 4-hour standard of 650 $\mu g/m^3$.

Table 4.4 RESULTS OF EPA MODELING

(SO$_2$ Concentrations in $\mu g/m^3$)

Run	Projected load condition	Maximum ground level conc. from power plant complex	Contribution of Piti Plant to maximum condition	Maximum ground level concentration from Piti Plant
1	1976-1 Cabras Unit down	319	240	241
2	1978-1 Cabras Unit down	375	224	226
3	1976-Normal	315	3	124
4	1977-Normal	465	5	80
5	1978-Normal	462	2	131
6	1978-Maximum	627	311	333
7	1978-Normal	141	106	127
8	1978-Maximum	714	101	248
9[a]	1978-Normal	53	7	10
10	1978-Normal	315	122	122
11	1978-Normal	1050	133	436

[a] All runs except Run 9 were individual maximum results and considered applicable to standards of up to 4 hour duration. Run 9 results are 24 hour average values.

The NCEL modeling study was directed to determining the maximum 24 hour average concentrations of sulfur dioxide under various load levels for the worst meteorological conditions. Meteorological conditions experienced on Guam on July 7, 1972, were considered as representative "worst" conditions. Parameter values for the day are presented in Table 4.5.

Table 4.5 METEOROLOGICAL CONDITIONS USED IN THE NCEL MODELING STUDY

3-hr segment no.	Wind direction degrees	Wind speed, m/sec	Stab class	Mixing ht, m	Temp., Deg K
1	270.0	2.5	5	700.0	299.0
2	260.0	1.5	5	700.0	299.0
3	260.0	0.5	2	700.0	298.0
4	260.0	4.0	3	700.0	302.0
5	280.0	4.0	3	700.0	302.0
6	280.0	0.5	2	700.0	302.0
7	250.0	3.0	3	700.0	300.0
8	270.0	2.5	5	700.0	300.0

Table 4.6 presents results of the NCEL modeling. Under no conditions were either the primary or secondary 24-hour levels for SO_2 exceeded. Even decreasing the assumed height of the Piti stacks to 150 feet in run 4 does not project a violation of the 24-hour standards.

Table 4.6 RESULTS OF NCEL MODELING[a]

(SO_2 Concentrations in $\mu g/m^3$)

Run	Projected load condition	Maximum ground-level conc. from power plant complex	Contribution of Piti plant to maximum condition	Maximum ground-level concentration from Piti plant
1	1976-Normal	39	12	15
2	1976-1 Cabras unit down	39	29	29
3	1978-1 Cabras unit down	53	29	29
4[b]	1976-Normal	41	14	18

[a] All results are 24-hr average values.

[b] 150-foot stack elevation discharge for Piti power plant was used for Run 4.

It should be noted, however, that results of the modeling of the Cabras and Piti plants do not constitute conclusive evidence that GPA can avoid violation of ambient air standards by installing 200-foot stacks at Piti and burning 0.75 percent-sulfur fuel. The model provides no means of representing the approximate effects of buildings or topography around the plants and uses only a few sets of the many meteorological conditions over a year's time. At best, the model can approximate only the order of magnitude of the concentration levels expected.

The other plants on Guam were not included in the modeling efforts. The Power Barge Inductance is in the same general area as the Piti and Cabras plants but would be difficult to model because of its short stacks. The Tanguisson Plant would be very difficult to model because of the surrounding topography. The plant is located below a 350-foot cliff; since the stacks are only 131 feet high, emissions are subjected to highly variable winds caused by the easterlies spiraling down the cliff as the wind leaves the plateau at the top of the cliff, as illustrated in Figure 4.3.

Although more elaborate models could be applied to the plants on Guam, they would still yield only arbitrary and approximate simulations of true conditions.

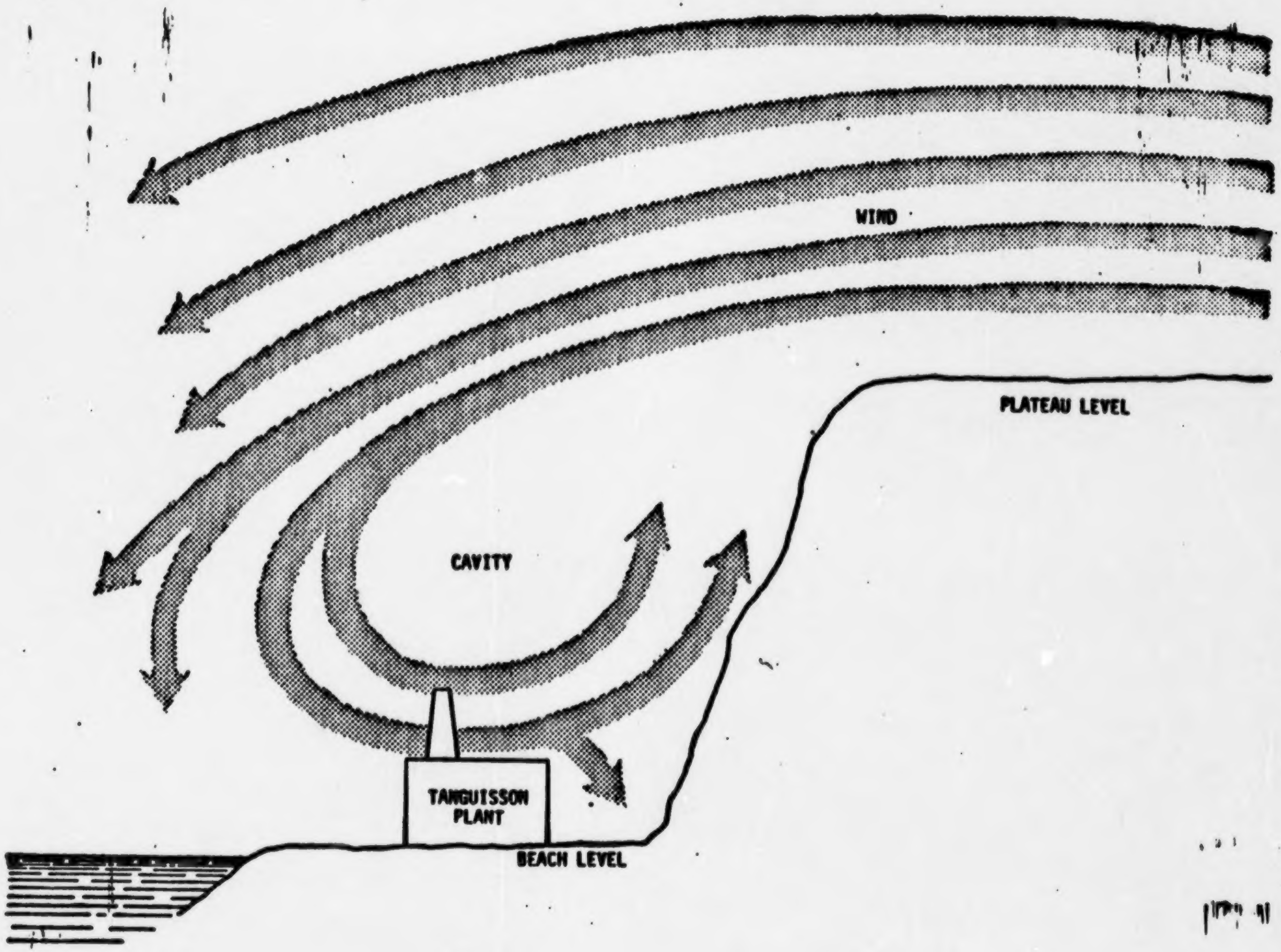


Figure 4.3 Illustration of topography at Tanguisson Plant.

5.0 CHARACTERISTICS OF THE GUAM FUEL OIL SUPPLY

5.1 FUEL OIL MARKET CONDITIONS

On September 16, 1974, GPA began purchasing No. 6 fuel oil for the Island-Wide Power System from the Guam Oil Refining Company (GORCO). GPA supplies No. 6 oil to both Navy PWC and GPA plants. Until that date, the Navy supplied all the fuel for Guam. The Navy still supplies the diesel fuel for GPA and Navy PWC diesel generator units. This fuel is procured off-island from the Caltex Petroleum Corporation.

The contract between GORCO and GPA (signed October 8, 1974) contains a clause that escalates the price charged for No. 6 fuel oil, cent by cent, using the OPEC crude price as a basis. On September 16, 1974, GORCO charged GPA $10.786/bbl for No. 6 fuel oil, the same price it was charging the Navy. At the time of the transfer, the Navy charged GPA $12.786/bbl for oil, since the Navy prices were based on the average price worldwide. Since that time the OPEC price has risen and GPA now pays GORCO $11.86/bbl for No. 6 oil. Although GORCO is able to escalate fuel costs, it is unable to pass through to the consumer increased operating costs.

GORCO stores oil for GPA at their plant and sells oil based on their tankage gradings. The GORCO contract permits sale to GPA of oil with a maximum sulfur content of 3.5

percent. The average fuel analysis is shown in Table 5.1

Table 5.1 AVERAGE ANALYSIS OF GPA FUEL OIL

Analysis	Composition
HHV, BTU/lb	18,740
Sulfur, %	3.1
Ash, %	0.1
Moisture, %	0.5 maximum
Sp. gravity	0.938

GPA obtained a variance from the Guam Environmental Protection Agency to burn oil with a sulfur content that does not meet regulations. The variance expires on December 31, 1975, the same date on which the oil contract ends.

The close of the Vietnam War caused a reduction in the sales at the GORCO Refinery because of decreasing military sales. Current rate of sale is approximately 18,000 bbl/day. Capacity of the refinery is 30,000 bbl/day. GPA is GORCO's only customer for No. 6 oil, using approximately 5500 bbl/day. GORCO supplies all the JP-4 military jet fuel used on the island. The Navy is the only market for this product. Other companies supply jet fuels to the commercial airlines. The light ends are sold as liquified petroleum gas (LPG) to three cooking-gas suppliers on the island. Excess light ends are used to run turbogenerators at the GORCO facility. At the present time, GORCO has no customer for the diesel fuel it produces. Diesel fuel used on the island by GPA and the Navy is supplied by Caltex.

5.2 AVAILABILITY OF LOW-SULFUR OIL ON THE OPEN MARKET

5.2.1 Availability

According to a survey of oil companies active in Far East markets, low-sulfur heavy fuel oil for Guam power plants is readily available at the present time in both the spot and long-term contract markets. Easing of the markets for petroleum fuels generally and for low-sulfur fuel oil in particular has stemmed from a variety of factors:

1. The worldwide recession
2. The tremendous rise in oil prices at the beginning of 1974.
3. Conservation efforts in many consuming nations.
4. Completion of the rebuilding of oil inventories drawn down during the Arab embargo.
5. A relatively mild winter in some of the major consuming areas, particularly in Europe.

A mail and telephone survey was conducted covering 22 oil companies domiciled in Japan and other Far East countries. Response to queries by mail was poor. Of twelve companies contacted by telephone, largely American oil companies, all but one indicated willingness to supply oil on Guam.

5.2.2 Fuel Oil Cost

The price a large consumer could negotiate with a supplier cannot be determined precisely. Low sulfur fuel oil (0.5 percent sulfur) is available from Indonesia and the Persian Gulf at a range of prices summarized in Table 5.2.

Table 5.2 FUEL OIL COST SUMMARY

Fuel type	Sulfur content, % S	Oil cost, $/bbl	Delivery cost, $/bbl	Total cost, $/bbl
Indonesian No. 6 fuel oil	0.8	12.70	0.50	13.20
Persian Gulf No. 6 fuel oil	0.8	10.95	1.00	11.95
Persian Gulf No. 6 fuel oil	3.4	9.75	1.00	10.75
Indonesian crude oil	0.1	12.60	0.50	13.10
Present fuel cost, GORCO	3.1			11.85

5.2.3 Contract Conditions

Although the market has eased and many oil suppliers have uncommitted products that they desire to sell, the suppliers are reluctant to enter into any long-term contracts unless the contract provides ample protection for significant changes in supplies and costs. Nationalization of part or all of the crude oil production in the major producing OPEC countries, tremendous changes in costs of crude, including taxes, and the Arab oil embargo have profoundly affected the international oil companies. Since these oil companies no longer control the supply and cost of much of the oil they sell, they are interested in long-term contracts only if these contracts cover escalations in price, retroactive increases in price to cover retroactive increase in cost, and losses of supply.

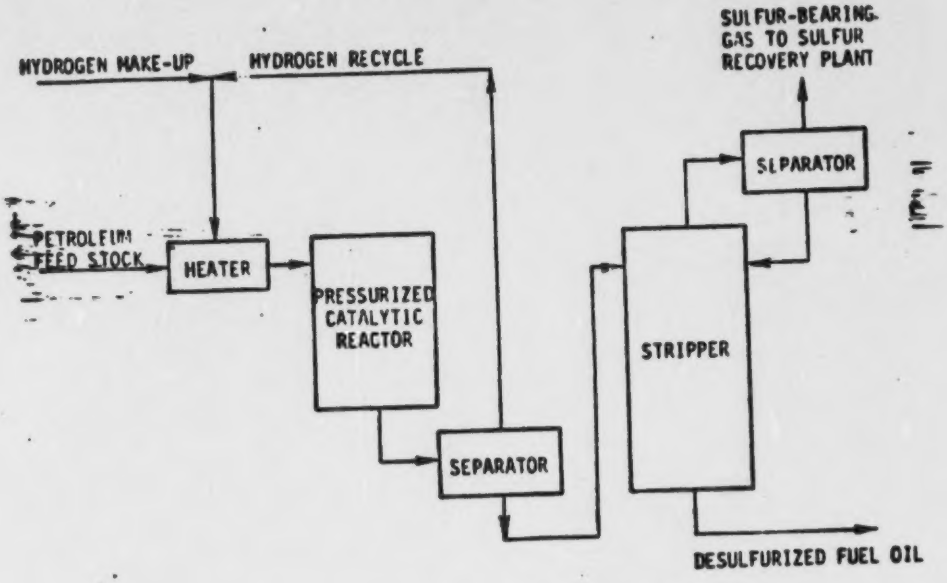
5.3 INSTALLATION OF FUEL OIL DESULFURIZATION FACILITIES

Direct and indirect desulfurization methods can be applied to convert low-metal Arabian crude into low-sulfur residual fuel. In the direct method, the heavy gas from the distillation tower and the residual fraction are treated at the same time to remove sulfur compounds. In the indirect process the gas, oil, and residual fractions are separated in a vacuum distillation step, the gas oil fraction is desulfurized, and this product is then blended with the residual fraction to yield a low-sulfur product.

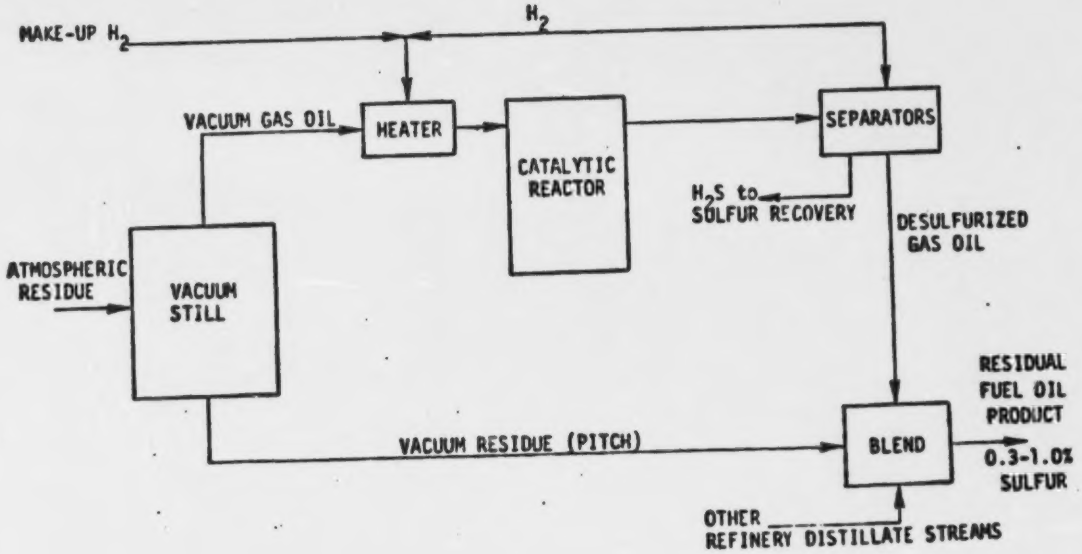
Simplified flow diagrams of the direct and indirect fuel oil desulfurization processes are shown in Figure 5.1. In each case the key to the process is the hydrogen treatment step, in which the sulfur reacts with the hydrogen to yield hydrogen sulfide. The hydrogen sulfide is then processed in a conventional sulfur recovery plant by the Claus process.

Capacities of most new desulfurization units being built today are in the 50,000 to 60,000 bbl/day range. The Guam Power Authority, however, uses only about 5500 bbl/day of residual fuel oil. Plants sized to meet GPA requirements are no longer being built.

Table 5.3 shows approximate costs of a 6000 bbl/day and a 50,000 bbl/day desulfurization plant. The costs are based on the direct desulfurization process, a low- metal Arabian crude with 2 percent sulfur, a finished low-sulfur fuel with



SIMPLIFIED DIRECT DESULFURIZATION PROCESS



SIMPLIFIED INDIRECT DESULFURIZATION PROCESS

Figure 5.1 Desulfurization processes.

Table 5.3 CAPITAL AND ANNUALIZED COSTS FOR FUEL OIL DESULFURIZATION UNITS

	50,000 BPD	6,000 BPD
Capital cost	$66,000,000	$12,000,000
Annual operating cost		
Labor: supervision - 0.5 men/shift @ $9.50/hr	0.23	1.27
operating - 4.0 men/shift @ $8.00/hr	1.63	8.17
Maintenance, 4% of capital cost	19.47	21.92
Heat, 180 M BTU/bbl, 1.97 MM BTU	35.53	35.53
Cooling, 90 M BTU/bbl, 2.6¢/M gal	0.34	0.34
Steam, 60 lb/bbl, 2.63/MM BTU	15.70	15.70
Power, 8-14 KW/bbl, 4.4¢ KWH	35.20	35.20
Boiler water, 6.5 gal/bbl, 30¢/M gal	0.20	0.20
Catalyst, 27-121 bbl/lb, 1.35¢/lb	5.03	5.03
Hydrogen, 600 cu ft, 1.97/MCF	118.20	118.20
Royalty, 6¢/bbl	6.00	6.00
Total direct charges, cents/bbl	232.53	248.36
Fixed charges at 20% of capital cost	72.33	109.58
Total cost, cents/bbl	304.86	357.94

0.7 percent sulfur, and the present fuel and utility costs on Guam.

The costs of refining low-sulfur fuel on Guam are summarized as follows:

	Plant size, bbl/day	
	50,000	6,000
Cost per bbl, $	3.05	3.58
Cost per MM BTU, $	0.49	0.58
Cost per KWH, mills	7.87	9.24

Because of the high price of crude, cost of low-sulfur fuels refined on Guam will be higher than that of low-sulfur fuels refined in an OPEC country. Costs of OPEC fuel oils are discussed in Section 6.1.

Before the October 1973 war in the Middle East, GORCO was planning to increase the size of the refinery from 30,000 BPD to 130,000 BPD. A 60,000-BPD fuel oil desulfurization unit was a part of this planned expansion; the bulk of the low-sulfur fuel was destined for the Japanese market. The project is now in suspension until the necessary long-term supplies of crude oil can be assured. Since the cost of low-sulfur fuel oil produced in a small unit is noncompetitive on the world market, GORCO has stated that it is unwilling to build a small unit unless it is guaranteed a customer. GPA has stated that it is unwilling to be tied to a single source.

6.0 ANALYSIS OF CONTINUOUS EMISSION CONTROL ALTERNATIVES

Continuous SO_2 emission control alternatives include use of low-sulfur fuel and flue gas desulfurization. Application of these alternatives to the GPA power plants is discussed in the following subsections.

6.1 LOW-SULFUR FUEL OIL

For management reasons involving the supply, storage, and distribution of fuel, the continuous use of low-sulfur fuel oil by Cabras would essentially require the use of low-sulfur fuel oil by all of the plants. To meet the sulfur dioxide emission regulation of 0.8 lb/MM BTU, fuel oil of the approximate analysis shown in Table 6.1 would be required.

Table 6.1 ANALYSIS OF FUEL OIL REQUIRED TO MEET NSPS

Analysis	Composition
HHV, BTU/lb	18,740
S, %	0.85
Ash, %	0.10
Specific gravity	0.938

Fuel oils of this analysis are available from Arabia and Indonesia. Table 6.2 identifies the cost of each oil and that of GPA's present fuel.

Table 6.2 COSTS OF CRUDE AND FUEL OILS

Fuel oil source	Cost parameter		Mills/KWH differential
	$/bbl	$/MM BTU	
GORCO high-sulfur (present fuel)	11.85	1.91	0
Arabian high-sulfur	10.75	1.73	(2.88)
Arabian low-sulfur	11.95	1.93	0.32
Indonesian low-sulfur	13.20	2.13	3.52
Indonesian low-sulfur (crude)	13.10	2.11	3.20

The average residential customer on Guam uses approximately 1000 kwh of electricity per month. The average residential rate is 5.7 cents/kwh, yielding an average residential bill of $57 per month. The cost differentials for use of low-sulfur fuel for the expected incremental cost range of low vs high sulfur fuel oil and their impacts on the residential rate are shown in Table 6.3.

Table 6.3 COST DIFFERENTIAL FOR USE OF LOW-SULFUR FUEL OILS

Option	Cost differential (1975)		Increase in average monthly bill $	Change in average monthly bill $
	$/year	mills/KWH		
Present fuel	0	0	0	0
Low sulfur fuel oil	0	0	0	0
$1.50/bbl incremental cost	2,855,000	3.87	3.87	6.8
$3.50 bbl incremental cost	6,661,000	9.03	9.03	15.8

Crude-oil firing was also investigated. Crude oil, however, is more expensive than the available No. 6 fuel oil; Indonesian crude is less expensive than Indonesian fuel oil, but both are significantly more expensive than Persian Gulf fuel oil. Thus, there is no economic incentive for burning crude oil.

6.2 FLUE GAS DESULFURIZATION

Four processes were considered for controlling SO_2 emissions: the Wellman-Lord, wet lime, wet limestone, and seawater scrubbing processes. Since Guam has no significant market for sulfur or sulfuric acid, the Wellman-Lord process was not considered beyond the preliminary evaluation of these by-product sulfur markets. Abundant low-cost limestone and lack of on-island lime production eliminated the wet lime process from further consideration; under these conditions wet lime scrubbing would not be competitive.

The following sections present brief process descriptions, process retrofit plans, and process costs for the wet limestone and seawater scrubbing processes. FGD system evaluations were conducted for the Cabras Units 1 and 2, and Tanguisson Units 1 and 2.

6.2.1 Process Descriptions

Wet Limestone Scrubbing - The limestone scrubbing system illustrated in Figure 6.1, utilizes a limestone ($CaCO_3$) slurry as the sulfur dioxide absorbent medium. The sulfur dioxide reacts with the limestone to form calcium

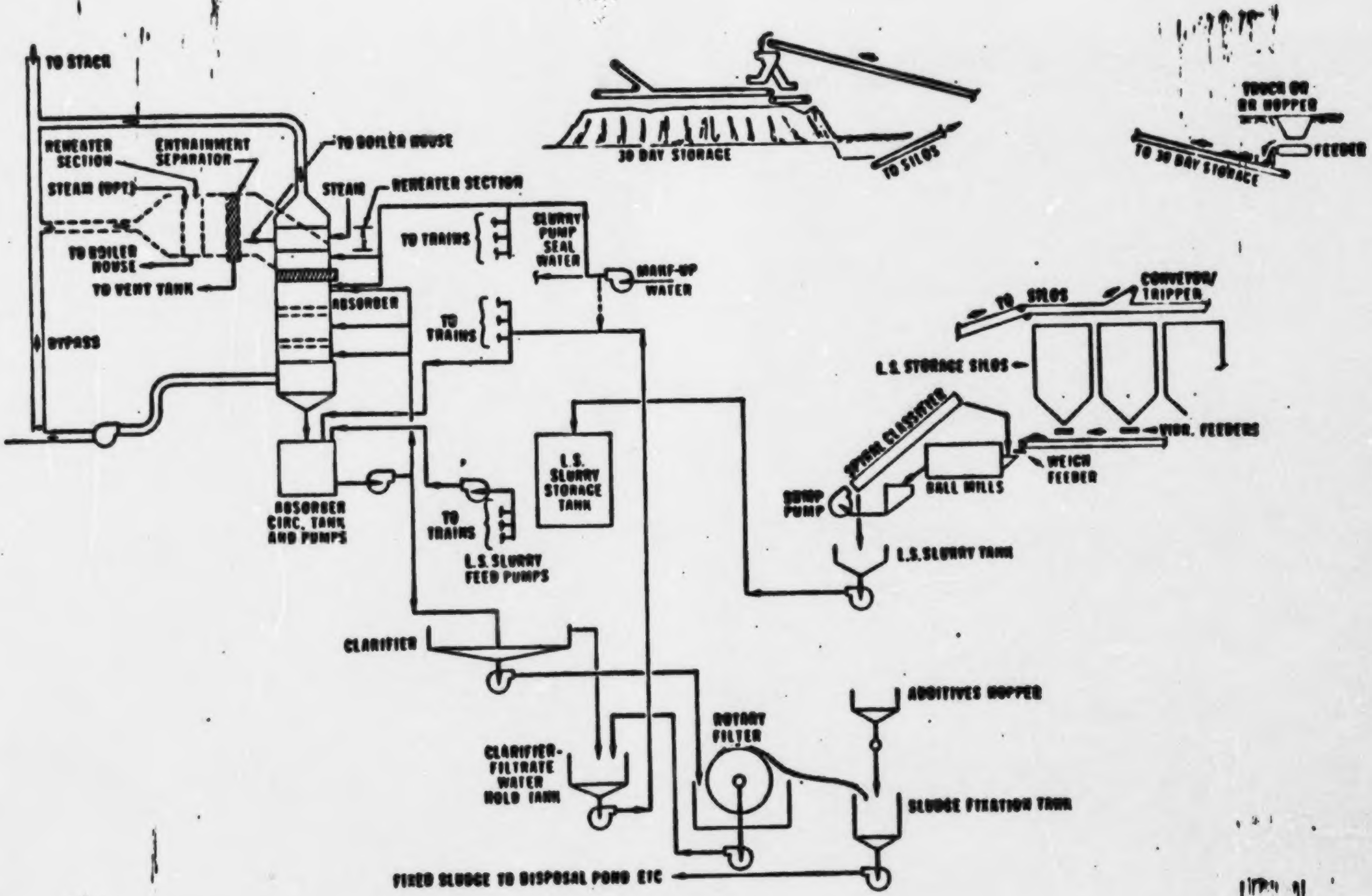


Figure 6.1 FGD process flow sheet.

sulfite ($CaSO_3$), which is removed from the system as a waste product. Flue gases from the boiler pass through a booster fan to overcome the pressure drop in the scrubbing system.

Flue gases from the boiler enter an absorber tower near the base, where quenching with water reduces the temperature of the gases before they ascend through the absorption section of the tower. The ascending flue gases are brought into contact with the limestone slurry in two or three stages for sulfur dioxide absorption. Concentrations of solids in the slurry range from 4 to 15 percent. Sulfur dioxide removal efficiencies are usually 85 percent or greater.

The scrubbed flue gases pass through a demister and are reheated prior to discharge to the atmosphere. Reheating is required to prevent plume fumigation and to raise the gas temperature far enough above the dew point to prevent excessive condensation.

Limestone slurry is prepared on the site by a wet ball milling process. The limestone system entails an open limestone storage area, handling and conveying equipment, live storage silos, wet ball mills, and slurry storage tanks.

Partial recovery of water is achieved through solid/liquid separation operations. The slurry leaving the absorber goes to the absorber circulation tank, where hydrated $CaSO_3$ and $CaSO_4$ crystals precipitate. A bleed stream containing these solids is sent to a gravity clarifier, where the crystals, fly ash, and unreacted limestone settle. The overflow from the clarifier and the filtrate are returned to the circulation tank. The underflow from the clarifier is processed in a rotary filter to produce a sludge with a moisture content of about 60 percent. The sludge is treated to prevent subsequent leaching by addition of chemicals in a mixing tank and is then trucked to a permanent disposal site. The treated or "fixed" sludge forms a stabilized fill material that can support vegetation and subsequent development.

The basis for process design determines the sizing and sparing of the equipment used in the limestone process. The design rationale used in this study is presented in Appendix E.

Seawater Scrubbing - The seawater scrubbing system utilizes the natural alkalinity of seawater for absorption of SO_2. The sulfur dioxide reacts with bicarbonate and hydroxyl ions to form sulfite ions. The sulfite ions, which may be oxidized to sulfate ions, are returned to the sea after the scrubbing process.

As in the limestone process, flue gases from the boiler enter the absorber tower near the base and are quenched with water before ascending through the absorber. The sulfur dioxide is removed in a countercurrent absorber. Sulfur dioxide removal efficiencies, which are a function of the seawater circulation rate are normally greater than 85 percent. The scrubbed flue gases pass through a demister and are reheated prior to discharge to the atmosphere.

Seawater is drawn into the plant through an inlet pipe from the ocean. The seawater makes a single pass through the absorber and is discharged into a water treatment facility in the ocean. A clarifier may be installed after the absorber to reduce suspended solid levels. If chemical oxidation demand (COD) reduction is required, the scrubber effluent is aerated in a pond.

Since the scrubber effluent is blended into the condenser cooling water discharge, total dissolved solids content is increased by only about 1 percent. Sludge disposal, if required, will handle the small portion of reaction products, unburned oil, and metals in the oil. Sludge stabilized with fixation chemicals is trucked to a permanent disposal site.

The process design basis is presented in Appendix E.

6.2.2 Retrofit Plan

Figure 6.2 and 6.3 illustrate possible locations for major system components for wet limestone and seawater scrubbing as applicable to Cabras and Tanguisson plants. The retrofit equipment layout is based on preliminary observations at both plants and discussions with plant personnel. A detailed engineering study would be required for design optimization.

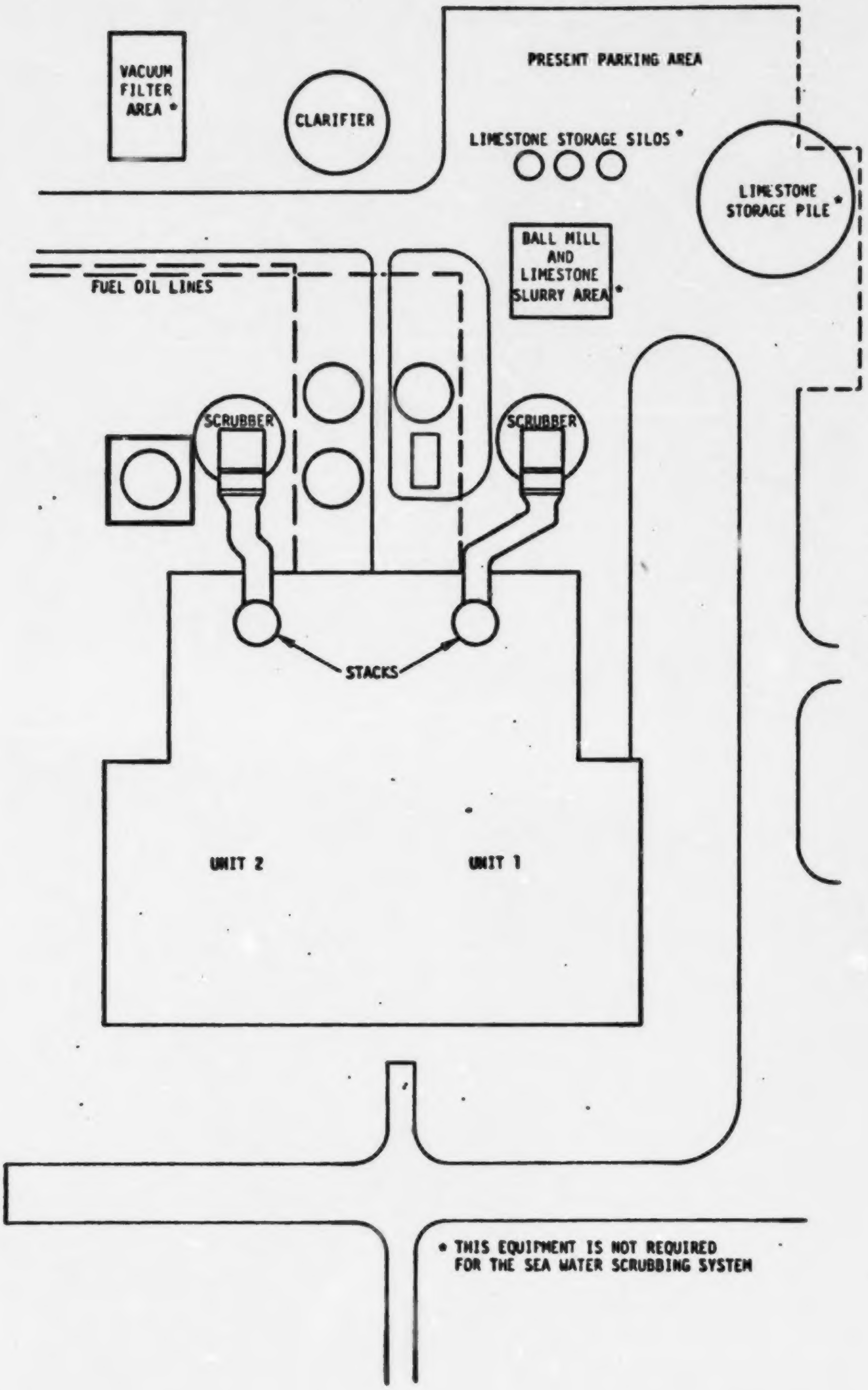

VACUUM FILTER AREA *
CLARIFIER
PRESENT PARKING AREA
LIMESTONE STORAGE SILOS *
LIMESTONE STORAGE PILE *
BALL MILL AND LIMESTONE SLURRY AREA *
FUEL OIL LINES
SCRUBBER
SCRUBBER
STACKS
UNIT 2
UNIT 1
* THIS EQUIPMENT IS NOT REQUIRED FOR THE SEA WATER SCRUBBING SYSTEM

Figure 6.2 Retrofit plan for flue gas desulfurization system on Cabras Units 1 and 2.

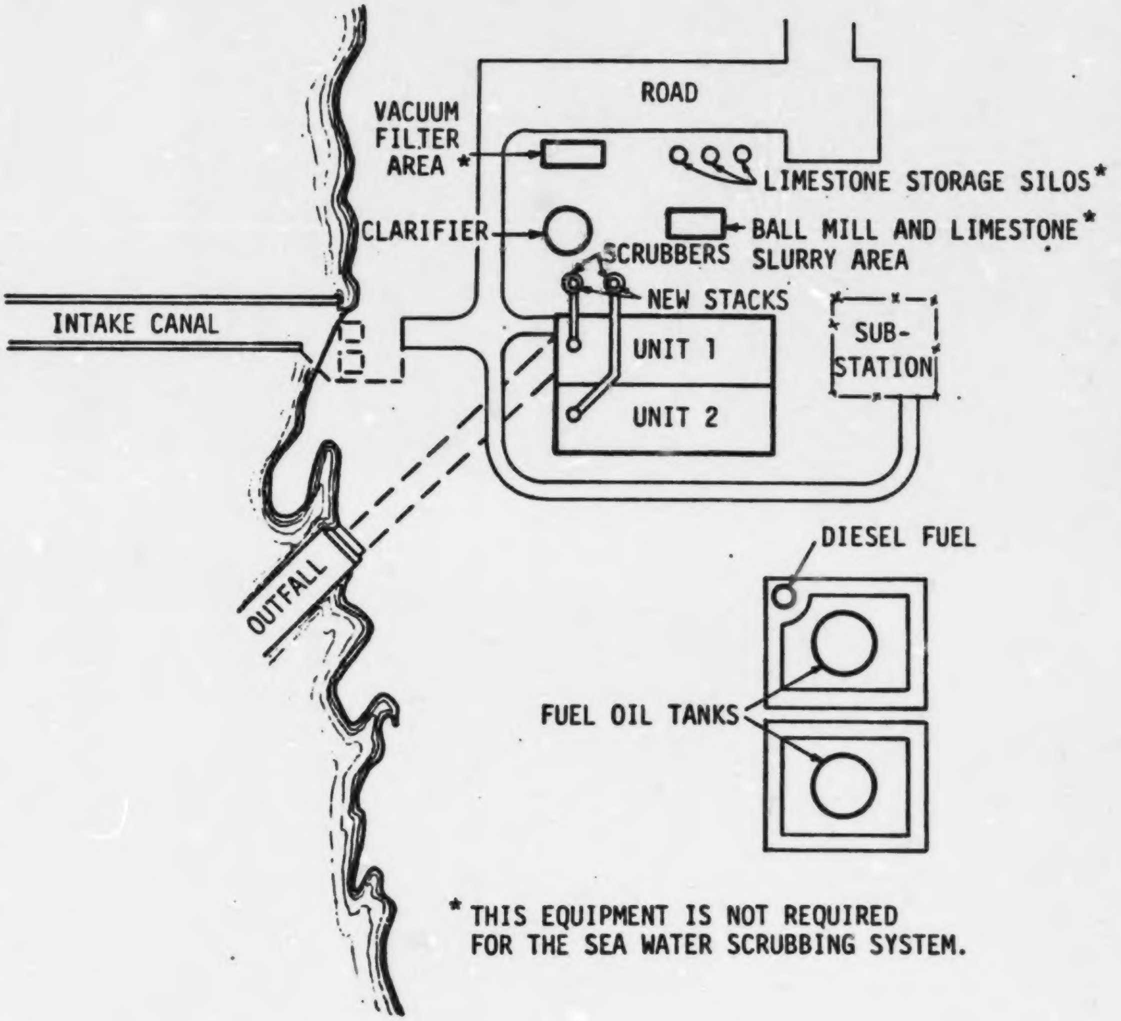


Figure 6.3 Retrofit plan for flue gas desulfurization system on Tanguisson Units 1 and 2.

For the Cabras plant, one scrubbing train of the required flue gas capacity would be required for each boiler in both the limestone and seawater systems. These scrubbing trains, together with their associated booster fans, would be installed in the area on the northwest side of the plant.

For the limestone system, the proposed location of the limestone storage and grinding facilities would be to the north of the scrubbing train on Unit 1. Since this area is now used as a parking lot, it would be necessary to relocate that facility. The limestone slurry at 60 percent moisture concentration would be pumped some 100 feet to the scrubbing modules.

Spent limestone liquor from the scrubbing trains would be pumped about 150 feet to the clarifier located northwest of the scrubbing trains. Clarifier sludge would then be pumped to the vacuum filtration area located about 40 feet southwest of the clarifier. In this area would be located the vacuum filters to dewater the sludge and fixation equipment to stabilize the sludge before disposal. The sludge would be trucked to an off-plant landfill disposal site. About 70 acre-feet per year of a landfill material would be generated.

Installation of a wet limestone scrubbing system on both boilers at the Cabras plant would require approximately 30 months, assuming an expeditious program of design, construction, and installation. Bringing the boilers off-line for tie-in of the FGD system will be of critical importance. By proper scheduling, it may be possible either to tie-in the FGD system or to modify ducting to facilitate future system tie-in by only slightly extending the scheduled annual or semiannual boiler/turbine outages.

The seawater scrubbing system would require only a clarifier in addition to the scrubbing trains. The small amount of sludge collected in the clarifier would be stabilized and trucked to a landfill site Liquid effluent would be diluted with plant cooling water before discharge into the ocean.

Installation of seawater scrubbers would require approximately 24 months, assuming an expeditious program of design, construction, and installation. As with the limestone scrubbing system, bringing the boilers off-line for tie-in of the scrubbing system is critical and should be scheduled during a boiler/turbine maintenance outage.

For the Tanguisson plant, one scrubbing train of the required flue gas capacity would be required for each boiler in both the wet limestone and seawater scrubbing systems. These scrubbing trains, with their associated booster fans, would be installed northeast of the plant building. A new stack would replace the existing stacks.

For the limestone system, two options were considered. In the first, the Tanguisson system is self-contained and requires limestone storage, grinding, and a slurry process area. The limestone storage silos would be located northeast of the plant near the entrance gate. Directly between the silos and the plant proper would be the grinding and slurry area. The slurry would be pumped about 60 feet to the scrubbing modules.

In the second option, facilities for limestone storage, grinding, and slurry would be located at the Cabras plant. Slurry would be trucked from the Cabras plant and stored in small clay tanks at Tanguisson.

Spent limestone liquor from the scrubbing trains would be pumped about 30 feet to the clarifier located northeast of the scrubbing trains. Underflow from the clarifier would be pumped to the vacuum filtration area located about 40 feet northeast of the clarifier. Vacuum filters and sludge fixation equipment would also be located in this area. The sludge would be trucked to an off-site landfill. The system would generate about 21 acre-feet of stabilized landfill per year.

Installation of a wet limestone scrubbing system on both boilers at the Tanguisson plant would require approximately 30 months, assuming an expeditious program of design, construction, and installation. Again, bringing the boilers off-line for tie-in of the system would be of critical importance.

The seawater scrubbing system in the Tanguisson plant would require only a clarifier in addition to the scrubbing trains. The small amount of sludge collected in the clarifier would be trucked to a landfill site. The treated liquid effluent would be diluted with plant cooling water before discharge into the ocean.

6.2.3 Cost Estimates

Cost estimates were prepared by standard engineering procedures. Verbal quotations from vendors were obtained for such major equipment items as pumps, storage tanks, absorbers, fans, ball mills, classifiers, vibrating feeders, and vacuum filters. Costs are modified to include freight rates to Guam and labor productivity on Guam.

Capital and annualized costs estimates for Tanguisson and Cabras plants are shown in Table 6.4, which also shows the anticipated increase in costs to the average residential consumers.

6.3 LOW-SULFUR COAL

Low-sulfur coal that would enable the plants to meet Guam regulations and NSPS is available from Australian mines located in Queensland about 90 miles from the coast in the Great Dividing Range. The average fuel analysis of the Blair-Athol, one of the Queensland mines, is shown in Table 6.5.

Table 6.4 FLUE GAS DESULFURIZATION CAPITAL AND ANNUALIZED OPERATING COSTS

Plant	Emission control alternative	Costs				Increase in average monthly residential bill	
		Capital		Annualized operating			
		MM $	$/KW	MM $	mills/KWH	$	%
Cabras Units 1 and 2	limestone	9.22	69.81	3.65	4.21	4.21	7.4
Cabras Units 1 and 2	seawater	5.38	40.74	1.85	2.13	2.13	3.7
Tanguisson Units 1 and 2	limestone	6.24	117.81	1.96	7.02	7.02	12.3
Tanguisson Units 1 and 2	seawater	3.18	59.91	1.06	3.82	3.82	6.7
Cabras Units 1 and 2 and Tanguisson Units 1 and 2	limestone	13.28	71.78	5.18	4.52	4.52	7.9

Table 6.5 AVERAGE ANALYSIS OF BLAIR-ATHOL COAL

Analysis	Composition
GHV, BTU/lb	11,000
Moisture, %	13.0
Ash, %	8.2
Sulfur, %	0.3
Ash fusion-liquid, °C	1,560

This coal is used as an extender for American coals in the manufacture of coke in Japan. During the current slump in the Japanese economy, this coal is available on Guam at a price equivalent to approximately $6.00/BBL oil. The Australian government, however, has proposed an export tax on coal which would raise the price of coal and lower the economic incentive to burn coal on Guam. The Blair-Athol Coal Company has recently reneged on some long-term contracts in which the price of coal was very low. It appears that on a long-term basis the price of Australian coal may equilibrate with that of OPEC oil.

The boilers for the Cabras plant were designed for high thermal efficiencies in burning oil. Using coal in these boilers would derate the units by 60 percent. Because of this large derating and the additional cost of equipment for coal firing, coal handling, and ash handling, it would be uneconomical to convert the Cabras 1 and 2 Units to coal.

If the price of Australian coal could be guaranteed at or near the $6.00/BBL oil equivalent, then serious consideration should be given to designing Cabras Units 3 and 4 for coal firing.

6.4 SOLID WASTE

Municipal refuse provides a viable source of energy in some localities. Table 6.6 presents data on the quantities of wastes generated by various segments of the Guam population.

Table 6.6 GUAM REFUSE INVENTORY

Segment	Refuse generated tons/year	Refuse type
Civilian	50,000 to 63,500	General refuse
U.S. Air Force	2,700	General refuse and military supplies
U.S. Navy	N.A.	General refuse and military supplies

The Guam Environmental Protection Agency has estimated that 140,000 TPY of waste were generated in 1970. If the waste tonnage has increased with the population, the tonnage in 1974 should be approximately 200,000 TPY.

If this quantity of refuse was collected and converted to fuel, it would only supply enough fuel for approximately 10 MW of capacity. Although this would only partially ease fuel requirements, it could alleviate a growing solid waste disposal burden on the Island. Further study is required to determine the feasibility of burning municipal refuse in GPA or Navy boilers. These units were designed for oil firing and do not have bottom ash collection systems. Furnace volume may be insufficient for burning significant quantities of refuse to supplement existing fuel. Furthermore the units are not equipped with particulate emission control equipment, which would be essential if refuse was fired. In addition to these power plant related questions, the adequacy of the refuse collection and transfer operations for providing a relatively constant supply of refuse, would have to be assessed.

7.0 ANALYSIS OF SUPPLEMENTAL EMISSION CONTROL SYSTEMS

A supplemental control system (SCS) is designed to enable a plant to meet air quality standards by adjusting SO_2 emission rates to reflect the continually changing dispersive capacity of the atmosphere. The SO_2 emissions from fossil-fuel-fired electric generating plants may be adjusted by two methods: (1) burning fuel of a lower sulfur content and (2) reducing the generating load on a particular plant and picking up the lost capacity at another plant in the system (load shifting). A third alternative is load shedding, which entails cutting power to certain consumers. Since this obviously impairs the reliability of electrical service, load shedding usually is not included as a viable alternative in SCS design.

In addition to the adjusting of emission rates, stack heights may be increased to enhance dispersion of SO_2 and reduce concentrations at ground level. Use of tall stacks reduces the frequency of potential violations of ambient air quality standards and hence the frequency of fuel switching or load reduction.

If it is to be effective in maintaining ambient air quality standards, an SCS must include all sources of sulfur dioxide. This is particularly true of the Guam power plants, since they are the major sources of sulfur dioxide on the island and several are in close proximity to one another.

The most effective and reliable SCS will allow some flexibility in the methods of reducing SO_2 emissions. The ideal system would include use of tall stacks to minimize periods for which SO_2 emission reductions will be necessary and the capability for use of various means of reducing SO_2 emissions. A system that provides a choice of burning low-sulfur fuel or shifting load is more reliable than one limited to a single method, since a situation may occur that precludes the use of that method. This is especially true of load shifting for the Guam power plants, since all the plants might be required to reduce emissions during the same period and load shifting would be ineffective.

The following sections describe a supplemental control system for the Guam power plants. The system is based on preliminary data for these plants and environs and does not represent a detailed engineering evaluation. Much more detailed meteorological data is necessary for a refined design of a supplemental control system.

7.1 OPERATING PLAN FOR SUPPLEMENTAL CONTROL SYSTEM

Three types of SCS may be employed; (1) open loop based on diffusion modeling, (2) closed loop, based on air quality monitoring, (3) closed loop, based on diffusion modeling upgraded by emissions data. Because most models do not effectively account for unusual topographic conditions, a closed-loop system is probably the most reliable for the Guam power plants.

The SCS should employ three complementary operations. Each emission source would first look at meteorological predictions, then apply a diffusion model and adjust its emission output accordingly (e.g., switch to low-sulfur fuels). If that adjustment were not sufficient, as indicated by air quality monitoring, procedures for further emission reduction would be activated. Records of the emissions, measured concentrations, and meteorological conditions would be analyzed periodically to determine whether the prediction accuracy of the model could be improved. Any improvements would then be incorporated into the model.

The advantage of a combined closed-loop system is that each of the loops performs a different function. The model allows lead time for performance of control operations. This is desirable in that time is required for switching fuel or curtailing generation. Furthermore, the lead time associated with the model provides valuable compensation for the lag between emission of pollutants and registration of their effects at the monitors. Even if all control functions were instantaneous, this lag could result in unacceptably high concentrations at the monitoring site(s) for limited time periods.

The air quality loop firmly establishes the connection between air quality and emissions from the plant. During the initial operation of a combined system, when the operating model is tentative and the dependency of air quality on local meteorology is only partially known, the air quality loop might often be the controlling one. As time goes on and data are accumulated, it should be possible to improve the operating model so that the air quality loop is activated less and less frequently and overall SCS operation becomes smoother and more predictable.

One factor that would limit application of an SCS to the Guam plants is the short stacks at the Piti plant. For most of the meteorological conditions in Guam, the Piti plant produces ground-level concentrations of SO_2 in excess of the standards. Taller stacks for the Piti plant would be a necessary part of any effective SCS applied to the Guam plants.

The equipment, personnel, and services required to establish a closed-loop SCS for the Guam power plants are listed in Table 7.1.

Table 7.1 EQUIPMENT AND SERVICES NEEDED IN AN SCS FOR THE GUAM POWER PLANTS

Equipment/service	Number required and applicability
Tall stack(s)	200 ft at Piti Plant
Emission rate monitoring equipment	1 at each plant
Meteorological monitoring equipment	2 sets: 1 for Tanguisson 1 for Piti, Cabras, Inductance
Air quality monitoring equipment	13 monitors
Computer/modeling services	1
Technical/scientific personnel	4 - 8 additional
Alternate fuel system	Low-sulfur oil for each plant

The emission rate monitoring equipment refers to a precombustion sulfur analysis of the fuel on a frequent basis and allows application of emission factors to predict SO_2 emissions from the stacks of each plant. Alternatively, the stacks could be equipped with continuous SO_2 flue gas monitors to provide emission rates for input to the dispersion model.

Meteorological monitoring equipment would consist primarily of devices to collect data for vertical wind and temperature profiles The devices may be affixed to pilot balloons mounted on fixed-wing aircraft. A ground-based network may also be established to record wind direction, wind speed, and temperature gradient or atmospheric stability.

The air quality monitoring equipment would be housed in a number of sampling stations around each source to provide coverage of the impact areas where maximum ground-level concentrations may occur. The monitors should be located so that the impact may be measured under prevailing conditions on Guam. Available data on air quality indicate that adequate coverage for each plant would be as follows:

1. Cabras - two monitors to the west of the plant and one to the east.
2. Piti - three monitors to the west and two to the east.
3. Inductance - one monitor to the east and one to the west.
4. Tanguisson - two monitors at beach level on each side of the plant and one monitor on the cliff behind the plant.

The sampling stations should be equipped with logging devices that provide machine-readable data to facilitate data handling and interpretation. Telemetry for real-time recording of the network data at a central station may be desirable.

Computer and modeling services will be required to implement the SCS. The computer will analyze the data collected by the air monitoring equipment and will use these values and current meteorological data to update the dispersion model developed for the sources. The dispersion model should have the capability to predict accurately any periods in which standards might be exceeded and to identify the plants that must switch fuels, and for what time period, to avoid violation of the standards. Development of a reliable model for the Guam plants may require extensive effort because the meteorology and topography that influence dispersion patterns are complex.

It is estimated that the personnel required to initiate and operate the SCS are an electrical engineer, two instrument mechanics, a meteorologist, a pilot baloon operator, one surface vehicle operator, a mathematician (computer programmer), and supporting clerical staff.

7.2 ANALYSIS OF FUEL SWITCHING POTENTIAL

All of the Guam power plants can burn low-sulfur oil with no problems. Each must add a storage tank and lines to handle the low-sulfur oil.

Additional storage is needed for the low-sulfur oil. A central tank would be located at the Cabras plant with a capacity equal to a 30-day supply of oil for all plants. This tank would hold approximately 16,300,000 gallons. Each of the other plants would have a tank holding a 12-day supply of oil. The Piti plant would require a 2,100,000-gallon tank; the Tanguisson plant a 1,200,000-gallon tank; and the Inductance a 710,000-gallon tank.

Earlier modeling studies indicate that the low-sulfur oil should have a sulfur content of 0.75 percent or less assuming that 200-foot stacks are installed on the Piti plant. If not, the Piti Plant must burn fuel having 0.3 percent sulfur or less almost constantly to avoid exceeding the standards.

More detailed meteorological data and analysis would be necessary to determine the amount of low-sulfur oil required annually to operate the SCS. It is probable that ambient air standards would be exceeded at times, even with the capability of using low-sulfur oil. More extensive and detailed data are necessary to predict the number of days standards would be exceeded.

7.3 ANALYSIS OF THE POTENTIAL OF LOAD SHIFTING

The location and topography of the power plants on Guam severly limit the use of load shifting as a means of reducing SO_2 emissions. The Cabras, Piti, and Inductance plants are in the same general area and adverse meteorological conditions would affect all of these plants; therefore, load switching among these units would not effectively reduce ground-level concentrations. Another limiting factor is that the Tanguisson plant is located on the same side of the island as the other plants and probably is affected by the same meteorological conditions. This further limits the potential for effective shifting of loads among the Guam power plants to prevent violation of ambient air standards.

7.4 ANALYSIS OF THE POTENTIAL FOR USE OF TALL STACKS

The purpose of a tall stack is to ensure that the plume remains clear of turbulent regions created by obstructions around the source. Two of the Guam plants, Piti and Tanguisson, have stacks that are too short to allow the plumes escape these turbulent regions.

Modeling studies conducted by NCEL for the Piti Plant show that the 24-hour ambient SO_2 standards could be met by installing two 200-foot-high stacks and burning 3.0 percent sulfur fuel oil. Topographical effects were not included in the model, however, and the validity of the prediction is therefore questionable. The EPA modeling effort indicated that short-term (4-hour) standards would be exceeded with the 200-foot stacks unless the sulfur content of the fuel were 0.75 percent or less. But the meteorological conditions assumed for this model were the worst theoretically possible, and it was assumed that these conditions would persist over the 4-hour period. This would be an infrequent occurrence, predictable by an effective SCS. Therefore any operable SCS should include installation of 200 foot stacks at the Piti plant. The stacks must be designed to withstand high-speed typhoon winds (up to 155 mph) and seismic loading. Such conditions are within present stack technology and are economically feasible.

The Tanguisson plant presents a difficult problem. The downwash affecting this plant results from the prevailing winds as they leave the plateau at the level of the 350-foot cliff above the plant and spiral down to the plant level. Enabling the plume to escape this effect would probably require a stack height of around 750 feet. A stack of this height would present a problem with winds from the west, since the plume would then produce high SO_2 levels on the plateau. Also, the economics of building a stack this high with sufficient structural strength to withstand 155-mph winds and Guam's seismic load would be prohibitive. For these reasons, use of a fuel of lower sulfur content is the best method by which the Tanguisson plant can avoid exceeding air quality levels. A detailed and exhaustive analysis would be required to determine the optimum combination of fuel sulfur content and stack height for Tanguisson.

8.0 GPA PROGRAM FOR COMPLYING WITH EMISSION STANDARDS

GPA proposed to comply with the New Source Performance Standards by burning low-sulfur fuel oil. They were twice unable to procure such fuel oil, however, when they requested bids. Furthermore, GPA is concerned with reducing the high cost of electric power on Guam. Even if low-sulfur fuel is available, they do not propose to burn it if it is more costly than the fuels now used.

GPA requested bids for sale of low-sulfur fuel oil on October 1, 1973, and July 1, 1974. They have made no other official requests for bids for low-sulfur fuel. A summary of the bid invitations and their responses is presented in Table 8.1. Only two companies responded to the first bid; neither offered low-sulfur fuel, and both bids were refused. On the second invitation to bid, only GORCO responded. No bid was received in the second round for low-sulfur oil. (Table 8.1 is incomplete, but includes all the relevant data provided by GPA).

The first invitation to bid was for a three year contract and the second was for a one year contract. The bid specifications required maintenance of a supply of oil

Table 8.1 SUMMARY OF GPA FUEL OIL BID RESPONSES

		October 1, 1973 Bid				July 1, 1974 Bid		
		Sulfur Content (%)				Sulfur Content (%)		
		0.54	0.80	3.25	Comment	0.80	3.25	Comment
1.	Mr. K. H. Parke, Secretary British Petroleum Co., Ltd. Britanic House, Moor Lane London E.C.2, United Kingdom			Available for one. Subject to change	Declined to bid on low sulfur fuel			Declined to bid
2.	Caltex Petroleum Corp. 380 Madison Avenue New York, New York 10017							
3.	Mr. Fred Cochrane Guam Oil & Refinery Co., Inc. P.O. Box 3190 Agana, Guam 96910			3.99	3.5% sulfur oil		10.78	3.5% sulfur
4.	Mr. B. C. Sholton Marketing Coordinator Gulf Oil Corporation Gulf Building P.O. Box 1166 Pittsburg, Pennsylvania 15230				Declined to bid. Suggested spot market			
5.	Mr. Lawrence King, Jr. Mobil Oil Corporation Manager, Government Sales 150 E. 42nd Street New York, New York 10017				Declined to bid. Asked for 60 days extension.			Declined to bid
6.	Nippon Oil Company, Ltd. 3-12, 1-Chome, Nishi Shimbashi Minator-ku, Tokyo 105, Japan							
7.	Mr. J. W. Sheehan, Vice President Shell Oil Company 50 West 50th Street New York, New York 10020				Declined to bid			
8.	Standard Oil Company Of Calif. Chevron Oil Trading Co. 555 Market Street San Francisco, Calif. 94105				Declined to bid			

Table 8.1 SUMMARY OF GPA FUEL OIL BID RESPONSES (continued)

	0.54	0.80	3.25	Comment	0.80	3.25	Comment
9. Standard Oil Co. (New Jersey) Esso International, Inc. 15 West 51st Street New York, New York 10019							
10. Mr. J. H. Pipkin Executive Vice President Texaco, Inc. 135 East 42nd Street New York, New York 10017				Declined to bid			
11. Mr. Yoshi Akagi, Asst. Mgr. C. Itoh & Co., Ltd. Import Fuel Oil Section 4, 2-Chome, Mon-Cho Kiho nbashi, Chuo-ku, Japan							
12. Asiatic Petroleum Corp. One Rockefeller Plaza New York, New York 10020							
13. Mr. Lionel Bevis Manager, Pacific Area Shell Oil Company Melbourne, Victoria 3000 Australia			$4.97				
14 Mr. Paul Dubrule Mobil Petroleum Co., Inc. General Manager P.O. Box EU Agana, Guam 96910							
15. Daikyo Oil Company Bridgestone Building 1-1 Kyobashi Chuo-ku, Tokyo, Japan							

Table 8.1 SUMMARY OF GPA FUEL OIL BID RESPONSES (continued)

	0.54	0.80	3.25	Comment	0.80	3.25	Comment
16. Nippon Oil Company 4-1-Chome Tamura-Cho Shiba, Minato-ku Tokyo, Japan							
17. Idemitsu Kosan 10, 1-Chome, Marunouchi Chiyoda-ku, Tokyo, Japan							
18. Maruzen Oil Company 1-3 Nagahoribashi-Suji Minami-ku, Osaka, Japan							
19. Mr. B. Austin, General Mgr. Pacific Gulf Oil P.O. Box 43 Atasaka, Tokyo, Japan							
20. Arabian Oil Company 1-6 Ohtemachi Chiyoda-ku, Tokyo, Japan							
21. Koa Oil Company Eiraku Building 1-2 Marunouchi Chiyoda-ku, Tokyo, Japan							
22. Mr. Frank R. Power General Manager Aminoil, Inc. Shin-Tokyo Building 3-1 Marunouchi, 3-Chome Chiyoda-ku, Tokyo, Japan							
23. Esso Standard Eastern, Inc. P.O. Box 3160 Agana, Guam 96910							Declined to bid

on Guam, 500,000 BBL in the first invitation and 185,000 BBL in the second; this supply provision required either that the successful bidder obtain tankage from GORCO, an unlikely event, or construct storage tanks.

9.0 ECONOMIC IMPACT OF EMISSION ON THE RESIDENTIAL CONSUMER

This section briefly analyzes the primary economic impact, namely increased electricity costs, on the residential consumer as a result of controlling SO_2 emisisons from the Cabras plant. Secondary impacts, for example, increased cost of goods and services due to higher electricity costs, were not analyzed.

The average (mean) residential usage is approximately 100 KWH per month. The average residential rate is 5.7 mills/KWH for an average residential bill of $57 per month. However the median usage is less than 1000 KWH per month. As shown by the residential amount statistics in Table 9.1, approximately 66% of the residential consumers use less than 1000 KWH per month.

Table 9.1 RESIDENTIAL ACCOUNTS STATISTICS (1974)

KWH usage	Percentage in category
0 - 500	36
501 - 1000	30
1001 - 1500	15
1501 - over	19

Thus the median consumer pays a lower monthly bill and in absolute dollars would pay less per month for emission control expenditures than average (mean) figures would indicate.

The four alternatives available for meeting the NSPS emission limitations for Cabras One are:

(1) Shut Cabras 1 down

(2) Burn low sulfur fuel oil

(3) Use a limestone based flue gas desulfurization system; and

(4) Use a seawater based flue gas desulfurization system

The monthly electricity bill under each of these alternatives and the difference between it and the current bill are presented in Table 9.2 for four different monthly consumption rates. For purposes of comparison, monthly bills under existing conditions are also presented. It is emphasized that these calculations are based upon average cost pass through provisions and do not necessarily reflect the procedures used by GPA to convert capital expenditures and operating and maintenance costs into revenue requirements. Any differences in procedure, however, should have only slight impact on the computed values.

The above analysis covers residential rates only. Since residential consumption is only 25% of the total consumption, commercial and governmental groups will pay a greater percentage for compliance. Over half the load is for Federal and military facilities. This group will pay the most for compliance with sulfur dioxide regulations.

Table 9.2 IMPACT ON THE RESIDENTIAL CONSUMER ALTERNATIVES FOR SO_2 EMISSION CONTROL

	250 KWH			750 KWH		
Compliance option	Monthly bill, $	Change in monthly bill, $	Change in monthly bill, %	Monthly bill, $	Change in monthly bill, $	Change in monthly bill, %
Existing conditions	17.73	0.00	0.00	44.08	0.00	0.00
Shut down Cabras 1	19.65	1.92	10.83	49.83	5.75	13.04
Low sulfur fuel oil						
Immediate switch[a]	17.81	0.08	0.45	44.32	0.24	0.54
Long term impact[b]	-	0.97	-	-	2.90	-
Limestone FGD system[c]	18.06	0.33	1.86	46.35	1.00	2.27
Seawater FGD system[c]	17.54	(0.19)	(1.06)	43.52	(0.56)	(1.27)

	1250 KWH			1750 KWH		
Compliance option	Monthly bill, $	Change in monthly bill, $	Change in monthly bill, %	Monthly bill, $	Change in monthly bill, $	Change in monthly bill, %
Existing conditions	69.93	0.00	0.00	95.78	0.00	0.00
Shut down Cabras 1	79.51	9.58	13.70	109.18	13.40	13.99
Low sulfur fuel oil						
Immediate switch[a]	70.33	0.40	0.57	96.34	0.56	0.58
Long term impact[b]	-	4.84	-	-	6.77	-
Limestone FGD system[c]	71.59	1.66	2.37	98.11	2.33	2.43
Seawater FGD system[c]	68.99	(0.94)	(1.34)	94.47	(1.31)	(1.37)

[a] Immediate switch refers to the conversion from existing fuel oil supplies to Arabian low sulfur oil which can be purchased at only a slight increase in cost.

[b] Long term impact refers to an expected incremental cost of $1.50/barrel between low and high sulfur oils. Actual monthly consumer bills were not calculated since this long term differential may still result in total costs less than or equal to present costs.

[c] Costs include credit for using a lower priced, high sulfur fuel oil ($10.75/bbl) in conjunction with the FGD system.

Although the study scope did not permit a complete evaluation, there were other areas which could possibly reduce electric bills on Guam. These areas include: lower debt coverage; lower purchase prices for Navy land and generation facilities; lower voltage transmission lines (for planned expansion); no fuel oil storage facilities; and smaller generation units (for planned expansions).

OMB No. 158S 74023

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Guam Power Authority
2. MAILING ADDRESS: P.O. Box 2977, Agana, Guam 96910
3. RESPONSIBLE OFFICER: P. E. Cavote
4. POSITION: Asst. General Manager
5. PLANT NAME: Cabras
6. PLANT LOCATION: Piti-Lot 257
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Lewis Knudson
8. POSITION: Plant Manager
9. POWER POOL Guam Power Pool
   Island Wide Power System

DATE INFORMATION GATHERED: December 11, 1975

PARTICIPANTS IN MEETING:

Cabras Plant (GPA)

Lewis Knudson, Plt. Mgr.	Guam Power Authority
Joe Chesnutt, Plt. Chemist	Guam Power Authority
John Smith	Guam Power Authority
Ed Yau	U.S. Navy
Geoffrey Burke	Guam Environmental Protection Agency
Tim Devitt	PEDCo-Environmental Specialists, Inc.
Tom Ponder	PEDCo-Environmental Specialists, Inc.
Don Hendricks	U.S. Environmental Protection Agency

	Boiler number				
	1		2		
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	0.094		0.094		
GRAINS/ACF	0.039		0.039		
LB/HR (FULL LOAD)	60.6 *		60.6 *		
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.					
LB/MM BTU	0.1		0.1		
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU	3.3		3.3		
LB/HR (FULL LOAD)	2154 *		2154 *		
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.					
LB/MM BTU	0.8		0.8		
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

* Values calculated at nameplate rating of 66 MW

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C. SITE DATA

1. U.T.M. COORDINATES ____________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 8-12'

3. SOIL DATA: BEARING VALUE Floating concrete mat 4' Thick

PILING NECESSARY ____________

4. DRAWINGS REQUIRED

PLOT PLAN OF SITE (CONTOUR)

EQUIPMENT LAYOUT AND ELEVATION

AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 99'

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N.A.

D. BOILER DATA

	Boiler number				
	1		2		
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Floating Base		Floating Base		
2. TOTAL HOURS OPERATION (19) Startup	8/18/74		May 1975		
3. AVERAGE CAPACITY FACTOR (19)	75%		75%		
4. SERVED BY STACK NO.	1		2		
5. BOILER MANUFACTURER	B&W		B&W		
6. YEAR BOILER PLACED IN SERVICE	1974		1975		
7. REMAINING LIFE OF UNIT	30		30		
8. GENERATING CAPACITY (MW)					
RATED (Nameplate)	66 MW		66 MW		
MAXIMUM CONTINUOUS	66 MW		66 MW		
PEAK	72 MW		72 MW		
9. FUEL CONSUMPTION:					
OIL RATED	4370		4370		
(GPH) MAXIMUM CONTINUOUS					
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19)					
OIL (1975) BBLS	534,446		105,079		
11. WET OR DRY BOTTOM	N.A.		N.A.		
12. FLY ASH REINJECTION (YES OR NO)	N.A.		N.A.		
13. STACK HGT ABOVE GRADE	200		200'		
14. I.D. OF STACK AT TOP	6.5'		6.5'		

Notes:

	Boiler number				
	1		2		
15. FLUE GAS CLEANING EQUIPMENT	NO CONTROL EQUIPMENT		NO CONTROL EQUIPMENT		
a) MECHANICAL COLLECTORS					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%) a)					
MASS EMISSION RATE (GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	10		10		

a) ESP designed for ____ per cent sulfur coal

Notes: 2% excess O_2, gas analysis

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	Boiler number				
	1		2		
17. FLUE GAS RATE (ACFM)*					
@ 100% LOAD SCFM @ 70°F, 14.7 psia	121,000		121,000		
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	334		334		
@ 75% LOAD	327		327		
@ 50% LOAD	310		310		
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	N.A.		N.A.		
@ 75% LOAD					
@ 50% LOAD					
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD	N.A.		N.A.		
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR) DISPOSAL METHOD	N.A.		N.A.		
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK	11' x 7'		11' x 7'		
23. ELEVATION OF TIE IN POINT TO STACK	53.6'		53.6'		
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)					

a) Identify source of values (test or estimate)

Notes: * 170,000 ACFM @ 270°F; 10% excess air

E. F.D. FAN DATA

	Boiler number				
	1		2		
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)	24.7 *		24.7 *		

Notes: * at maximum load

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)

2. YEARS STORAGE (ASH ONLY)

3. DISTANCE FROM STACK (FT.)

4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

a.
b.
c.
d.

2. QUANTITY USED BY SEAM AND/OR MINE

a.
b.
c.
d.

3. ANALYSIS (average and range)

GHV (BTU/LB)
S (%)
ASH (%)
MOISTURE (%)

4. ESP PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (average and range)

1. TYPE No. 6 or Navy Special Fuel Oil

2. S CONTENT (%) 0.5 to 3.1, 3.5% max.

3. ASH CONTENT (%) 0.01 to 0.1

4. SPECIFIC GRAVITY 0.938

5. GHV (BTU/GAL) 18740 BTU/lb

I. COST DATA

ELECTRICITY
WATER
STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE? 90 MW excess capacity

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE? 115 volts - 4130

OMB No. 158S 74023

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Public Works Center U.S. Navy
2. MAIN OFFICE: Apra Harbor
3. RESPONSIBLE OFFICER: Captain Wolf
4. POSITION: Commanding Officer
5. PLANT NAME: Piti Power Plant
6. PLANT LOCATION: Piti Village
7. RESPONSIBLE OFFICER AT PLANT LOCATION: R.L. Duncan
8. POSITION: General Foreman
9. POWER POOL Guam Power Pool
   Island Wide Power System

DATE INFORMATION GATHERED: December 11, 1974

PARTICIPANTS IN MEETING:

Bob Duncan	U.S. Public Works Center
Ed Yau	U.S. Navy
Geoffrey Burke	Guam Environmental Protection Agency
Tim Devitt	PEDCo-Environmental Specialists, Inc.
Tom Ponder	PEDC--Environmental Specialists, Inc.
Don Hendricks	U.S. Environmental Protection Agency

	Boiler number				
	1	2	3	4	5
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	0.054	0.054	0.054	0.054	0.054
GRAINS/ACF	0.018	0.018	0.018	0.028	0.028
LB/HR (FULL LOAD)	9.1	9.1	9.1	15.6	15.6
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.					
LB/MM BTU	0.1	0.1	0.1	0.1	0.1
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU	3.3	3.3	3.3	3.3	3.3
LB/HR (FULL LOAD)	552	552	552	946	946
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.					
LB/MM BTU	0.8	0.8	0.8	0.8	0.8
b) FUTURE REQUIREMENT (DATE: July 1 1975)					
REGULATION & SECTION NO.					
LB/MM BTU					

Particulate and SO_2 emissions are estimates

C. SITE DATA

1. U.T.M. COORDINATES __________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 9.0'

3. SOIL DATA: BEARING VALUE __________

   PILING NECESSARY 60' Piling

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 60' 5"

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N.A.

D. BOILER DATA

	Boiler number				
	1	2	3	4	5
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Floating	Floating	Floating	Floating	Floating
2. TOTAL HOURS OPERATION (19)	N.A.	N.A.	N.A.	N.A.	N.A.
3. AVERAGE CAPACITY FACTOR (19)	N.A.	N.A.	N.A.	N.A.	N.A.
4. SERVED BY STACK NO.	1	2	3	4	5
5. BOILER MANUFACTURER	C-E	C-E	C-E	C-E	C-E
6. YEAR BOILER PLACED IN SERVICE	1951	1951	1953	1964	1965
7. REMAINING LIFE OF UNIT	6	6	6	20	20
8. GENERATING CAPACITY (MW)					
RATED	11.5	11.5	11.5	22.5	22.5
MAXIMUM CONTINUOUS	11.5	11.5	11.5	22.5	22.5
PEAK		13.0	13.0	25.0	25.0
9. FUEL CONSUMPTION:					
OIL (GPH) RATED	1134	1134	1134	1945	1945
MAXIMUM CONTINUOUS					
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19)	N.A.	N.A.	N.A.	N.A.	N.A.
OIL (GPY) (19)	N.A.	N.A.	N.A.	N.A.	N.A.
11. WET OR DRY BOTTOM	N.A.	N.A.	N.A.	N.A.	N.A.
12. FLY ASH REINJECTION (YES OR NO)	N.A.	N.A.	N.A.	N.A.	N.A.
13. STACK HGT ABOVE GRADE	88'8"	88'8"	88'8"	75'7"	75'7"
14. I.D. OF STACK AT TOP	7' 11"	7'11"	7' 11"	7' 6"	7' 6"

Notes: Units 1, 2, and 3 each 200,000 lb./hr. steam @ 635 psig & 825°F

Units 4 and 5 each 220,000 lb./hr. steam @ 875 psig and 905°F

The turbine for Unit 1 is no longer in service

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	Boiler number				
	1	2	3	4	5
15. FLUE GAS CLEANING EQUIPMENT	No Control Equipment	No Control Equipment	No Control Equipment	No Control Equipment	No Control Equipment
a) MECHANICAL COLLECTORS					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE:					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR					
MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%) a)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	N.A.	N.A.	N.A.	15	15

a) ESP designed for _____ per cent sulfur coal

Notes:

	Boiler number				
	1	2	3	4	5
17. FLUE GAS RATE (ACFM)b					
@ 100% LOAD	58200	58200	58200	65500	65500
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)a					
@ 100% LOAD	322	322	322	324	324
@ 75% LOAD					
@ 50% LOAD					
19. EXIT GAS STACK VELOCITY (FPS)a					
@ 100% LOAD	N.A.	N.A.	N.A.	N.A.	N.A.
@ 75% LOAD					
@ 50% LOAD					
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)	N.A.	N.A.	N.A.	N.A.	N.A.
DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)	N.A.	N.A.	N.A.	N.A.	N.A.
DISPOSAL METHOD					
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK FT.	8.0	8.0	8.0	4.5 x 8.3	4.5 x 8.3
23. ELEVATION OF TIE IN POINT TO STACK	21'	21'	21'	8'11 3/4"	8'11 3/4"
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)	2 weeks	2 weeks	2 weeks	3 weeks	3 weeks

a) Identify source of values (test or estimate)

Notes: Air preheater
210°F - 220°F
b - estimated

E. **I.D. FAN DATA**

	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)
2. YEARS STORAGE (ASH ONLY)
3. DISTANCE FROM STACK (FT.)
4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION
   a.
   b.
   c.
   d.
2. QUANTITY USED BY SEAM AND/OR MINE
   a.
   b.
   c.
   d.
3. ANALYSIS (average and range)
   GHV (BTU/LB)
   S (%)
   ASH (%)
   MOISTURE (%)
4. ESP PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (average and range)

1. TYPE No. 6 or Navy Special Fuel Oil
2. S CONTENT (%) 0.5 to 3.1, 3.5% max.
3. ASH CONTENT (%) 0.01 to 0.10
4. SPECIFIC GRAVITY 0.938
5. GHV (BTU/GAL) 18,740 BTU/lb

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE? Adequate

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Guam Power Authority
2. MAIN OFFICE: P.O. Box 2977, Agana, Guam 96910
3. RESPONSIBLE OFFICER: P.E. Cavote
4. POSITION: Asst. General Manager
5. PLANT NAME: Tanguisson
6. PLANT LOCATION: Parcel 1, Estate 103, Dededo, Guam
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Dave Knight
8. POSITION: Plant Manager
9. POWER POOL Guam Power Pool
   Island Wide Power System

DATE INFORMATION GATHERED: December 12, 1974

PARTICIPANTS IN MEETING:

Dave Knight, Plt. Mgr.	Guam Power Authority
Frank Melder, Results Engineer	Guam Power Authority
John Smith	Guam Power authority
Geoffrey Burke	Guam Environmental Protection Agency
Ed Yau	U.S. Navy
Tim Devitt	PEDCo-Environmental Specialists, Inc.
Tom Ponder	PEDCo-Environmental Specialists, Inc.
Don Hendricks	U.S. Environmental Protection Agency

B. ATMOSPHERIC EMISSIONS

	Boiler number				
	1	2			
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	0.094	0.094			
GRAINS/ACF	0.04	0.04			
LB/HR (FULL LOAD)	20.3	20.3			
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.					
LB/MM BTU	0.1	0.1			
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU	3.3	3.3			
LB/HR (FULL LOAD)	1004.4	1004.4			
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.	0.8	0.8			
LB/MM BTU					
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					

C. SITE DATA

1. U.T.M. COORDINATES __________

2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 20'

3. SOIL DATA: BEARING VALUE N.A.

   PILING NECESSARY __________

4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA

5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 56'

6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N.A.

D. BOILER DATA

	Boiler number				
	1	2			
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Base load	Base load			
2. TOTAL HOURS OPERATION (19)	N.A.	N.A.			
3. AVERAGE CAPACITY FACTOR (19 75)	60%	60%			
4. SERVED BY STACK NO.	1	2			
5. BOILER MANUFACTURER	C-E	C-E			
6. YEAR BOILER PLACED IN SERVICE	9-1-71	12-28-72			
7. REMAINING LIFE OF UNIT	30	30			
8. GENERATING CAPACITY (MW)					
RATED	26.5	26.5			
MAXIMUM CONTINUOUS					
PEAK					
9. FUEL CONSUMPTION:					
OIL RATED					
(GPH) MAXIMUM CONTINUOUS	2050	2050			
PEAK MINIMUM	673	673			
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19)					
OIL (1975) BBLS	312,000				
11. WET OR DRY BOTTOM	N.A.	N.A.			
12. FLY ASH REINJECTION (YES OR NO)	N.A.	N.A.			
13. STACK HGT ABOVE GRADE	131'	131'			
14. I.D. OF STACK AT TOP	4'8"	4'8"			

Notes:

	Boiler number				
15. FLUE GAS CLEANING EQUIPMENT a) MECHANICAL COLLECTORS MANUFACTURER	NO CONTROL EQUIPMENT	NO CONTROL EQUIPMENT			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE: (GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%) [a]					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	15	15			

---

a) ESP designed for _____ per cent sulfur coal

Notes:

	Boiler number				
	1	2			
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	99,748	99,748			
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)^a					
@ 100% LOAD	310	310			
@ 75% LOAD					
@ 50% LOAD					
19. EXIT GAS STACK VELOCITY (FPS)^a					
@ 100% LOAD	99.4	99.4			
@ 75% LOAD					
@ 50% LOAD					
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD	N.A.	N.A.			
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD	N.A.	N.A.			
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK					
23. ELEVATION OF TIE IN POINT TO STACK					
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)	21 days per year	21 days per year			

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)

2. YEARS STORAGE (ASH ONLY)

3. DISTANCE FROM STACK (FT.)

4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

a.

b.

c.

d.

2. QUANTITY USED BY SEAM AND/OR MINE

a.

b.

c.

d.

3. ANALYSIS (average and range)

GHV (BTU/LB)

S (%)

ASH (%)

MOISTURE (%)

4. ESP PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (average and range)

1. TYPE No. 6 or Navy Special Fuel Oil

2. S CONTENT (%) 0.5 to 3.1, 3.5% max.

3. ASH CONTENT (%) 0.01 to 0.10

4. SPECIFIC GRAVITY 0.938

5. GHV (BTU/GAL) 18,740 BTU/lb

I. COST DATA

ELECTRICITY

WATER

STEAM

J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE?

NORMAL LOAD ON PLANT SUBSTATION?

VOLTAGE AT WHICH POWER IS AVAILABLE?

OMB No. 158S 74023

POWER PLANT SURVEY FORM

A. COMPANY INFORMATION:

1. COMPANY NAME: Guam Power Authority
2. MAIN OFFICE: P.O. Box 2977, Agana, Guam 96910
3. RESPONSIBLE OFFICER: P. E. Cavote
4. POSITION: Asst. General Manager
5. PLANT NAME: Power Barge Inductance
6. PLANT LOCATION: Polaris Point, Inner Harbor
7. RESPONSIBLE OFFICER AT PLANT LOCATION: Mr. Arnaiz
8. POSITION: Plant Manager
9. POWER POOL Guam Power Pool
   Island Wide Power System

DATE INFORMATION GATHERED: December 11, 1974

PARTICIPANTS IN MEETING:

Inductance Plant (GPA)

A.B. Annaiz, Plt. Mgr.	Guam Power Authority
John Smith	Guam Power Authority
Geoffrey Burke	Guam Environmental Protection Agency
Tim Devitt	PEDCo-Environmental Specialists, Inc.
Tom Ponder	PEDCo-Environmental Specialists, Inc.
Don Hendricks	U. S. Environmental Protection Agency

	Boiler number				
	1	2			
B. ATMOSPHERIC EMISSIONS					
1. PARTICULATE EMISSIONS[a]					
LB/MM BTU	0.066	0.066			
GRAINS/ACF	0.047	0.047			
LB/HR (FULL LOAD)	12	12			
TONS/YEAR ( )					
2. APPLICABLE PARTICULATE EMISSION REGULATION					
a) CURRENT REQUIREMENT					
AQCR PRIORITY CLASSIFICATION					
REGULATION & SECTION NO.					
LB/MM BTU	0.1	0.1			
b) FUTURE REQUIREMENT (DATE:)					
REGULATION & SECTION NO.					
LB/MM BTU					
3. SO_2 EMISSIONS[a]					
LB/MM BTU	3.3	3.3			
LB/HR (FULL LOAD)	600	600			
TONS/YEAR ( )					
4. APPLICABLE SO_2 EMISSION REGULATION					
a) CURRENT REQUIREMENT					
REGULATION & SECTION NO.					
LB/MM BTU	0.8	0.8			
b) FUTURE REQUIREMENT (DATE: July 1 1975)					
REGULATION & SECTION NO.					
LB/MM BTU					

C. SITE DATA

1. U.T.M. COORDINATES ______
2. ELEVATION ABOVE MEAN SEA LEVEL (FT) 20' top deck
3. SOIL DATA: BEARING VALUE N.A.

   PILING NECESSARY ______
4. DRAWINGS REQUIRED

   PLOT PLAN OF SITE (CONTOUR)

   EQUIPMENT LAYOUT AND ELEVATION

   AERIAL PHOTOGRAPHS OF SITE INCLUDING POWER PLANT, COAL STORAGE AND ASH DISPOSAL AREA
5. HEIGHT OF TALLEST BUILDING AT PLANT SITE OR IN CLOSE PROXIMITY TO STACK (FT. ABOVE GRADE) 20' above top deck
6. HEIGHT OF COOLING TOWERS (FT. ABOVE GRADE): N.A.

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D. BOILER DATA

	Boiler number				
	1	2			
1. SERVICE: BASE LOAD STANDBY, FLOATING, PEAK	Peak	Peak			
2. TOTAL HOURS OPERATION (19)	N.A.	N.A.			
3. AVERAGE CAPACITY FACTOR (19)	30%	30%			
4. SERVED BY STACK NO.	1	2			
5. BOILER MANUFACTURER	B&W	B&W			
6. YEAR BOILER PLACED IN SERVICE	1971	1971			
7. REMAINING LIFE OF UNIT Built 1943	3	3			
8. GENERATING CAPACITY (MW)					
RATED	14 MW	14 MW			
MAXIMUM CONTINUOUS					
PEAK					
9. FUEL CONSUMPTION:					
OIL (GPH) RATED	1230	1230			
MAXIMUM CONTINUOUS					
PEAK					
10. ACTUAL FUEL CONSUMPTION					
COAL (TPY) (19)					
OIL (1975) BBLS	167,358 BBLS for the two units				
11. WET OR DRY BOTTOM	N.A.	N.A.			
12. FLY ASH REINJECTION (YES OR NO)	N.A.	N.A.			
13. STACK HGT ABOVE GRADE	64'	64'			
14. I.D. OF STACK AT TOP	6'2"	6'2"			

Notes:

	Boiler number				
	1	2			
15. FLUE GAS CLEANING EQUIPMENT a) MECHANICAL COLLECTORS MANUFACTURER	No Control Equipment	No Control Equipment			
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%)					
MASS EMISSION RATE:					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
b) ELECTROSTATIC PRECIPITATOR MANUFACTURER					
TYPE					
EFFICIENCY: DESIGN/ACTUAL (%) a)					
MASS EMISSION RATE					
(GR/ACF)					
(#/HR)					
(#/MM BTU)					
NO. OF IND. BUS SECTIONS					
TOTAL PLATE AREA (FT^2)					
FLUE GAS TEMPERATURE @ INLET ESP @ 100% LOAD (°F)					
16. EXCESS AIR: DESIGN/ACTUAL (%)	15	15			

a) ESP designed for _____ per cent sulfur coal

Notes:

	Boiler number				
	1	2			
17. FLUE GAS RATE (ACFM)					
@ 100% LOAD	60,000	60,000			
@ 75% LOAD					
@ 50% LOAD					
18. STACK GAS EXIT TEMPERATURE (°F)[a]					
@ 100% LOAD	380	380			
@ 75% LOAD					
@ 50% LOAD	320	320			
19. EXIT GAS STACK VELOCITY (FPS)[a]					
@ 100% LOAD	20	20			
@ 75% LOAD					
@ 50% LOAD					
20. FLY ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD	N.A.	N.A.			
DISPOSAL COST ($/TON)					
21. BOTTOM ASH: TOTAL COLLECTED (TONS/YEAR)					
DISPOSAL METHOD	N.A.	N.A.			
DISPOSAL COST ($/TON)					
22. EXHAUST DUCT DIMENSIONS @ STACK	≈6'	≈6'			
23. ELEVATION OF TIE IN POINT TO STACK	≈6'	≈6'			
24. SCHEDULED MAINTENANCE SHUTDOWN (ATTACH PROJECTED SCHEDULE)	Every 6 months				

a) Identify source of values (test or estimate)

Notes:

E. I.D. FAN DATA

	Boiler number				
1. MAXIMUM STATIC HEAD (IN. W.G.)					
2. WORKING STATIC HEAD (IN. W.G.)					

Notes:

F. FLY ASH DISPOSAL AREAS

1. AREAS AVAILABLE (ACRES)

2. YEARS STORAGE (ASH ONLY)

3. DISTANCE FROM STACK (FT.)

4. DOES THIS PLANT HAVE PONDING PROBLEMS? DESCRIBE IN ATTACHMENT

G. COAL DATA

1. COAL SEAM, MINE, MINE LOCATION

a.

b.

c.

d.

2. QUANTITY USED BY SEAM AND/OR MINE

a.

b.

c.

d.

3. ANALYSIS (average and range)

GHV (BTU/LB)

S (%)

ASH (%)

MOISTURE (%)

4. ESP PERFORMANCE EXPERIENCED WITH LOW S FUELS (DESCRIBE IN ATTACHMENT)

H. FUEL OIL DATA (average and range)

1. TYPE No. 6 or Navy Special Fuel Oil

2. S CONTENT (%) 0.5 to 3.1, 3.5% max.

3. ASH CONTENT (%) 0.01 to 0.1

4. SPECIFIC GRAVITY 0.938

5. GHV (BTU/GAL) 18,740 BTU/lb.

I. COST DATA

ELECTRICITY

WATER

STEAM

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J. PLANT SUBSTATION CAPACITY

APPROXIMATELY WHAT PERCENTAGE OF RATED STATION CAPACITY CAN PLANT SUBSTATION PROVIDE? 2 @ 1500 KVA each

NORMAL LOAD ON PLANT SUBSTATION? about 6%

VOLTAGE AT WHICH POWER IS AVAILABLE? 13800 - 440

APPENDIX E

BASIS OF PROCESS DESIGN

The process design basis for the wet limestone system and the seawater scrubbing system used in this study was determined after review of process designs used or proposed for use at various installations and discussions with control system manufacturers.

Values of the major overall design parameters for the Cabras and Tanquisson plants are tabulated below:

A. Cabras Plant

- Flue gas temperature: Units 1-2: 334°F
- Flue gas pressure: atmospheric
- Average inlet SO_2 concentration: 3.30 lb/MM BTU (3.1% S oil)
- Outlet SO_2 concentration: (aver.) 3.30 lb/MM BTU (present)
- Outlet SO_2 concentration: 0.8 lb/MM BTU (allowable)
- Reheat: 50°F above dew point (from 125 to 175°F)

1. Wet Limestone System

Two cases were evaluated. In Case 1 the Cabras plant system is completely separate from the Tanquisson plant system. In Case 2 the limestone storage, grinding, and slurrying facilities for both plants is located at Cabras. The actual scrubbing system remains the same for both cases.

a. Design Values

Limestone Consumption: 130% stoichiometric

Limestone Handling, Slurrying System

Case 1

Unloading Hopper: 25 ton capacity

Dead Storage Pile: 30 days storage

Feeders, Conveyors: Capacity = 5.8 x Maximum Limestone Flow

Live Storage Silos: 3 days storage

Ball Mills: 2-2 tons/h capacity units

Limestone Slurry Storage Tank: 24 hours storage

Limestone Slurry Feed Pumps: 1 pump/train with 1 spare for each 2 operating pumps.

Raw Water Pumps: 2

Case 2

Unloading Hopper: 25 ton capacity

Dead Storage Pile: 30 days storage (both plants)

Feeders, Conveyors: Capacity = 5.8 x Maximum Limestone Flow (both plants)

Live Storage Silos: 3 days storage (both plants)

Ball Mills: 2-3 tons/h capacity units

Limestone Slurry Storage Tank: 24 hours storage (both plants)

Limestone Slurry Feed Pumps: 1 pump/train with 1 spare for each 2 operating pumps.

Raw Water Pumps: 2

Sludge System

Clarifier: 1 unit

Sludge Pond: Proposed disposal sites are abondoned barrow pits on Cabras Island and Nimitz Hill, and are of sufficient size to accommodate the required 70 acre-feet per year for the remaining plant life of 30 years.

Scrubbing System (Each Train)

Fan: 1-100% unit
Type - Double inlet centrifugal
$\Delta P = 16.4" H_2O$

Absorber: Type - TCA with 2 beds
$\Delta P = 7" H_2O$
L/G = 65 GPM/AMCFM (inlet gas to absorber scrubber)

Slurry Concentration = 8% (wt.)
SO_2 Removal = 80%+
Gas Velocity = 10 FPS
Circulating Tank - 10 minutes retention
Pumps = 3/unit plus 1 spare pump for every 2 units

Entrainment Separator: Chevron vane-type
Number passes = 2
ΔP = 2" H_2O
Gas Velocity = 7 FPS

Reheater: Type - indirect tubular
ΔT = 50°F (inlet temperature = 125°F;
outlet temperature = 175°F)
Heating Medium - low pressure steam

b. Design Rationale

The design rationale used in the study are listed below:

- The unloading hopper was sized to hold 25 tons in order to accommodate unloading of trucks.
- The limestone dead storage pile was sized for 30 days to allow the plant to continue operating in the event of an interruption in the supply of limestone.
- The live storage silos were sized for 3 days storage.
- The feeders and conveyors were sized at 5.8 times the maximum limestone flow to allow the unloading of limestone during a 40 hour week while the plant operates continuously.
- For Case 1, 2-2 tons/h capacity ball mills were provided and sized to allow the power plant to generate at maximum capacity while burning high sulfur content oil. In the event 1 mill was out of service, the other mill could keep the plant operating for 56 hours.
- For Case 1, the limestone slurry storage tank was sized for 24 hours storage to allow the scrubbing trains to continue operating for 56 hours with 1 mill out of service or for 24 hours if maintenance required complete shutdown of the 2 ball mills.
- For Case 2, 2-3 ton/h capacity ball mills were provided and sized to allow both plants to generate at maximum capacity while burning high sulfur content oil. In the event 1 mill was out of service, the other mill could keep the plants operating for 82 hours.
- For Case 2, the limestone slurry storage tank was sized for 24 hours storage (both plants) to allow the scrubbing trains to continue operating for 82 hours with 1 mill

out of service or for 30.5 hours with both mills out of service. In addition there is a twenty-four storage at Tanquissor.

- In general, all pumps in the process are provided with spares.

- 1 thickener to concentrate the effluent slurry from 15% solids to 30% solids and then discharge the 30% effluent slurry to the vacuum filtration unit (1 unit at a rate capacity of 10 tons/hour). The effluent leaves the filtration unit as a slurry 60% by weight and then enters a mixing tank where the fixation additives are stirred in with the slurry and then trucked to the barrow pits for disposal.

- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has 2 beds of hollow plastic spheres which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 GPM/MACFM (inlet gas to the absorber) and a pressure drop of 7" H_2O. Slurry concentration will be 8%; gas velocity in the unit will be 10 FPS; and SO_2 removal is specified to be about 80% plus. The size of the turbulent contact absorber will be 15' x 16' approximately for units 1 & 2 in cross-section and will treat 121,000 ACFM, respectively of saturated gas (corresponding to about 66 MW nominal).

- Each absorber has a circulating tank sized to provide a 10-minute retention time based on the slurry circulating rate. This retention time is essentially the same as that reported by others and should provide sufficient time for desupersaturation and thus reduce scaling potential.

  However, if long retention times are required, the incremental cost would be small since the circulating tanks do not represent large cost items, but space limitations may require locating a secondary tank some distance away and require additional piping.

- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O. Design of the unit is based on information from C-E, Chemico and UOP.

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* Universal Oil Products Company (Air Correction Division).

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for it for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground level concentration, etc. For this study, a reheat ΔT of 50°F was used; this is believed to be about the minimum acceptable value. Obviously, the lowest acceptable reheat ΔT should be chosen since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

  An indirect finned tubular heat exchanger was selected for the reheater. The first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas which enters at it's dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low pressure saturated steam. Pressure drop through the reheater is calculated to be about 4" H_2O.

- Based on experience at Will County, a retractable B & W type soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers will be on the entry side, the remainder on the exit side of the heat exchanger.

2. Seawater

a. Design Values

Scrubbing System (Each train)

Raw Water Pumps: 2

Fan: 1-100% unit
Type - Double inlet centrifugal
ΔP - 16.4" H_2O

Absorber: Type - TCA with 2 beds
ΔP = 7" H_2O
L/P = 65 GPM/MACFM (inlet gas to absorber scrubber)
SO_2 Removal = 80%+
Gas Velocity = 10 FPS
Pumps = 3/unit plus 1 spare pump for every 2 units

Entrainment Separator: Chevron vane-type
Number passes = 2
ΔP = 2" H_2O
Gas Velocity = 7 FPS

Reheater: Type - indirect tubular
ΔT = 50°F (inlet temperature = 125°F;
outlet temperature = 175°F)
Heating Medium - low pressure steam

Effluent Treatment

Clarifier: 1 unit

b. Design Rationale

The design rationale used in the study are listed below:

- In general, all pumps in the process are provided with spares.

- 1 clarifier is utilized to remove suspended solids (heavy metals for oil) from the effluent. Note that no provision has been made to aerate the effluent though this could be necessary. The clarifier discharge is diluted with condenser cooling water before discharge into the ocean.

- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has 2 beds of hollow plastic spheres which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 GPM/MACFM (inlet gas to the absorber) and a pressure drop of 7" H_2O. Gas velocity in the unit will be 10 FPS; and SO_2 removal is specified to be about 80% plus. The size of the turbulent contact absorber will be 15' x 16' approximately for units 1 and 2 in cross-section and will treat 121,000 ACFM, respectively of saturated gas (corresponding to about 66 MW nominal).

- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O. Design of the unit is based on information from C-E, Chemico and UOP.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground level concentration, etc.

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* Universal Oil Products Company (Air Correction Division).

For this study, a reheat ΔT of 50°F was used; this is believed to be about the minimum acceptable value. Obviously, the lowest acceptable reheat ΔT should be chosen since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

An indirect finned tubular heat exchanger was selected for the reheater. The first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas which enters at it's dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low pressure saturated steam. Pressure drop through the reheater is calculated to be about 4" H_2O.

- Based on experience at Will County, a retractable B & W type soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers will be on the entry side, the remainder on the exit side of the heat exchanger.

B. Tanguisson Plant

- Flue gas temperature: units 1-2: 310°F
- Flue gas pressure: atmospheric
- Average inlet SO_2 concentration: 3.30 lb/MM BTU (3.1% S Oil)
- Outlet SO_2 concentration: (aver.) 3.30 lb/MM BTU (present)
- Outlet SO_2 concentration: 0.8 lb/MM BTU (allowable)
- Reheat: 50°F above dew point (from 125 to 175°F)

1. Wet Limestone System

Two cases as described under the Cabras Plant are evaluated. For Case 1, the Tanguisson Plant has separated limestone slurrying facilities, while for Case 2, it has none.

a. Design Values

- Limestone consumption = 130% stoichiometric

Limestone Handling, Slurrying System

Case 1

Unloading Hopper: 25 ton capacity

Dead Storage Pile: 30 days storage

Feeders, Conveyors: Capacity = 5.8 x Maximum Limestone Flow

Live Storage Silos: 3 days storage

Ball Mills: 1-3 tons/h capacity unit

Limestone Slurry Storage Tank: 24 hours storage

Limestone Slurry Feed Pumps: 1 pump/train with 1 spare for each 2 operating pumps

Raw Water Pumps: 2

Case 2

Limestone Slurry Storage Tank: 24 hours

Limestone Slurry Feed Pumps: 1 pump/train with 1 spare for each 2 operating pumps.

Sludge System

Clarifier: 1 unit

Sludge pond: proposed disposal sites are abandoned barrow pits near Dededo that are of sufficient size to accommodate the required 21 acre-feet per year for the remaining plant life of 30 years.

Scrubbing System (Each Train)

Fan: 1-100% unit
Type - Double inlet centrifugal
ΔP = 16.4" H_2O for units 1-2

Absorber: Type - TCA with 2 beds
ΔP = 7" H_2O
L/G = 65 GPM/MACFM (inlet gas to absorber scrubber)
Slurry Concentration = 8% (wt.)
SO_2 Removal = 80%+
Gas Velocity = 10 FPS
Circulating Tank - 10 minutes retention
Pumps = 3/unit plus 1 spare pump for every 2 units

Entrainment Separator: Chevron vane-type
Number passes = 2
ΔP - 2" H_2O
Gas Velocity - 7 FPS

Reheater: Type - indirect tubular
ΔP = 50°F (inlet temperature = 125°F;
outlet temperature = 175°F)
Heating Medium - low pressure steam

b. Design Rationale

The design rationale used in the study are listed below:

- The unloading hopper was sized to hold 25 tons in order to accommodate unloading of trucks.
- The limestone dead storage pile was sized for 30 days storage to allow the plant to continue operating in the event of an interruption in the supply of limestone.
- The live storage silos were sized for 3 days storage.
- The feeders and conveyors were sized at 5.8 times the maximum limestone flow to allow the unloading of limestone to take place during a 40 hour week while the plant operates continuously.
- For Case 1, the 3 tons/h ball mill was provided and sized to allow the power plant to generate at maximum capacity while burning high sulfur content oil.
- For Case 1, the limestone slurry storage tank was sized for 24 hours storage to allow the scrubbing trains to continue operating for 24 hours with the mill out of service.
- For Case 2, the limestone slurry storage tank was sized for 24 hours storage to allow the scrubbing trains to continue operating for 82 hours with 1 ball mill out of service at the Cabras Plant or for 30.5 hours with both ball mills at Cabras out of service.
- In general, all pumps in the process are provided with spares.
- 1 thickener to concentrate the effluent slurry from 15% solids to 30% solids and then discharge the 30% effluent slurry to the vacuum filtration unit (1 unit at a rated capacity of 4 tons/hour). The effluent leaves the filtration unit as a slurry 60% by weight and then enters a mixing tank where the fixation additives are stirred in with the slurry and then trucked to the barrow pit for disposal.
- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has 2 beds of hollow plastic spheres which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 GPM/

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* Universal Oil Products Company (Air Correction Division).

MACFM (inlet gas to the absorber and a pressure drop of 7" H_2O. Slurry concentration will be 8%; gas velocity in the unit will be 10 FPS; and SO_2 removal is specified to be about 80% plus. The size of the turbulent contact absorber will be 15' x 11' approximately for both units, and will treat about 100,000 ACFM, respectively of saturated gas (corresponding to about 26.5 MW nominal), respectively.

- Each absorber has a circulating tank sized to provide a 10-minute retention time based on the slurry circulating rate. This retention time is essentially the same as that reported by others and should provide sufficient time for desupersaturation and thus reduce scaling potential.

  However, if long retention times are required, the incremental cost would be small since the circulating tanks do not represent large cost items, but space limitations may require locating a secondary tank some distance away and require additional piping.

- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O. Design of the unit is based on information from C-E, Chemico and UOP.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground level concentration, etc. For this study, a reheat ΔT of 50°F was used; this is believed to be about the minimum acceptable value. Obviously, the lowest acceptable reheat ΔT should be chosen since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

  An indirect finned tubular heat exchanger was selected for the reheater. The first 33% of the rows of tubes are constructed of Alloy 20 for corrosion resistance to the gas which enters at it's dew point. The remaining 67% of the rows are constructed of carbon steel. Heating medium for the unit is low pressure saturated steam. Pressure drop through the reheater is calculated to be about 4" H_2O.

- Based on experience at Will County, a retractable B & W type soot blower is used for each 25 ft^2 of scrubber exit duct cross-section for the heat exchanger. Half of the soot blowers will be on the entry side, the remainder on the exit side of the heat exchanger.

2. Seawater Scrubbing System

a. Design Values

Scrubbing System (Each Train)

Raw Water Pumps: 2

Fan: 1-100% unit
Type - Double inlet centrifugal
$\Delta P = 16.4"\ H_2O$

Absorber: Type - TCA with 2 beds
$\Delta P = 7"\ H_2O$
L/G = 65 GPM/MACFM (inlet gas to absorber scrubber)
SO_2 Removal = 10 FPS
Gas Velocity = 10 FPS
Pumps = 3/unit plus 1 spare pump for every 2 units

Entrainment Separator: Chevron vane-type
Number passes = 2
$\Delta P = 2"\ H_2O$
Gas Velocity = 7 FPS

Reheater: Type - indirect tubular
ΔT = 50°F (inlet temperature = 125°F;
outlet temperature = 175°F)
Heating Medium - low pressure steam

Effluent Treatment

Clarifier: 1 unit

b. Design Rationale

The design rationale used in the study are listed below:

- The general, all pumps in the process are provided with spares.
- 1 clarifier is utilized to remove suspended solids (heavy metals from oil) from the effluent. Note that no provision has been made to aerate the effluent though this could be necessary. The clarifier discharge is diluted with condenser cooling water before discharge into the ocean.

- A UOP* Turbulent Contact Absorber (TCA) was selected for removal of the bulk of the SO_2. This unit has 2 beds of hollow plastic spheres which move randomly between support grids and provide the contact area necessary for mass transfer of SO_2 from the gas to the liquid phase. The absorber is designed for an L/G of 65 GPM/MACFM (inlet gas to the absorber) and a pressure drop of 7" H_2O. Gas velocity in the unit will be 10 FPS; and SO_2 removal is specified to be about 80% plus. The size of the turbulent contact absorber will be 15' x 11' approximately for both units in cross-section and will treat 100,000 ACFM, respectively of saturated gas (corresponding to about 26.5 MW nominal).

- The Chevron vane-type entrainment separator was selected to remove mist which is carried over in the gas from the absorber. This unit contains two stages of Chevron vanes which are washed continuously with water. Superficial gas velocity through the unit is 7 FPS and the pressure drop is expected to be about 2" H_2O. Design of the unit is based on information from C-E, Chemico and UOP.

- The gas leaving the entrainment separator must be reheated to desaturate it and provide buoyancy for it for adequate atmospheric dispersion. The number of degrees of reheat necessary is variable and dependent on a number of factors such as stack height, local weather conditions, population density, terrain of the area, maximum allowable SO_2 ground level concentration, etc. For this study, a reheat ΔT of 50°F was used; this is believed to be about the minimum acceptable value. Obviously, the lowest acceptable reheat ΔT should be chosed since each increase of 50°F of the flue gas temperature requires about 1.5% of the gross heat input to the plant.

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